# The Effect of Injected Water Salinity on Oil Recovery

by

Adib Abdul-Mohsen Al-Mumen

A Thesis Presented to the

FACULTY OF THE COLLEGE OF GRADUATE STUDIES

KING FAHD UNIVERSITY OF PETROLEUM & MINERALS

DHAHRAN, SAUDI ARABIA

In Partial Fulfillment of the
Requirements for the Degree of

**MASTER OF SCIENCE**

In

**PETROLEUM ENGINEERING**

May, 1990

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This thesis, written by Mr. Adib Abdulmohsen Al-Mumen under the direction of his Thesis Advisor and approved by his Thesis Committee, has been presented to and accepted by the Dean of the College of Graduate Studies, in partial fulfillment of the requirements for the degree of MASTER OF SCIENCE in Petroleum Engineering.

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**Dedicated to my wife**

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## NOMENCLATURE

$A$ = Cross sectional area, $cm^2$

API = American Petroleum Institute

$D$ = Diameter, cm

EDS = Energy Dispersive Spectrum

$f_w$ = Fractional flow of water

$g$ = Acceleration due to gravity, $cm/s^2$

ICP = Inductivity Coupled Plasma

IFT = Interfacial tension, dyne/cm

IOIP = Initial Oil in Place

$K$, $K_{abs}$ = Absolute permeability, md

$k_{eo}$ = Effective permeability to oil, md

$k_{ew}$ = Effective permeability to water, md

$k_{ro}$ = Relative permeability to oil

$k_{rw}$ = Relative permeability to water

$L$ = Length, cm

$N_{ca}$ = Capillary number

P.V. = Pore volume, $cm^3$

$\frac{dPc}{dx}$ = Capillary pressure gradient

$q_t$ = Volumetric flow rate, $cm^3/s$

$S_{wi}$ = Irrudicible water saturation

$S_{or}$ = Residual oil saturation

TDS = Total dissolved solids

V = Interstitial velocity, cm/s

GREEK SYMBOLS

$\varphi$ = Porosity

$\mu_o$ = Oil viscosity, cp

$\mu_w$ = Water viscosity, cp

$\frac{\mu_o}{\mu_w}$ = Viscosity ratio

$\rho$ = Density, $gm/cm^3$

$\sigma_{ow}$ = Interfacial tension between oil and water, dyne/cm

## خلاصة الرسالة

اسم الطالب الكامل : أديب عبدالمحسن علي المؤمن
عنوان الدراســـــة : تأثير ملوحة الماء المحقون على إستخلاص الزيت
التخصـــــــــص : هندسة البترول
تاريخ الشهـــــادة : شوال ، ١٤١٠هـ

أجريت تجارب غمر عينات لبيه بالماء لدراسة تأثير ملوحة الماء المحقون على إستخلاص الزيت . لقد أجريت هذه التجارب عند درجة حرارة تساوي ٩٠°م وصافي ضغط تحميل قدره ١٥٠٠ رطل/بوصة $^{٢}$ بإستخدام عينات لبيه من صخور البيريا الرملية والزيت العربي الخفيف . تم غمر العينات المشبعة بالزيت الخام بماء يحتوي على تراكيز مختلفة من كلوريد الصوديوم ( من ٥٥٠٠ الى ٢٠٠٠٠٠ ملغم/لتر ) وبماء البحر المعالج وبماء من طبقة الوسيع وبماء اصطناعي يماثل ماء طبقة العرب – د .
أثبتت الدراسة أنه كلما إزدادت ملوحة الماء المحقون ، كلما زادت كمية الزيت المستخلص وذلك حتى تركيز ١٠٠٠٠٠ ملغم/لتر ، حيث انه لم يلحظ أي زيادة ذات قيمة بعدها . ويعزى ذلك للإنخفاض الذي طرأ على قيم التوتر البيني مع ازدياد ملوحة الماء حتى تركيز ١٠٠٠٠٠ ملغم/لتر ، وأن قيم التوتر البيني بدأت بالإرتفاع الطفيف مع ازدياد ملوحة الماء بعدها . كما وجد أن نسبة النفاذية النسبية للزيت إلى النفاذية النسبية للماء تزداد مع زيادة ملوحة الماء المحقون .
أظهرت اختبارات الانسجامية أنه عندما يخلط ماء من طبقة العرب – د مع ماء البحر عند درجة حرارة تساوي ٩٠°م ، تترسب كبريتات الكالسيوم . إلا أن التحاليل التي أجريت على عينات من الماء المنساب من غمر العينات اللبيه لم تظهر أي مشاكل إنسجامية عند حقن ماء طبقة الوسيع أو ماء البحر .

درجة الماجستير في العلوم
جامعة الملك فهد للبترول والمعادن
الظهران – المملكة العربية السعودية
شوال ١٤١٠هـ

## THESIS ABSTRACT

Full Name of Student: Adib Abdulmohsen Al-Mumen.

Title of Study: THE EFFECT OF INJECTED WATER SALINITY ON OIL RECOVERY

Date of Degree: May 1990

Coreflooding experiments were performed to study the effect of injected water salinity on oil recovery. The experiments were conducted at a temperature of 90°C and a net overburden pressure of 1500 psi using Berea sandstone core samples and Arabian Light crude oil. Different concentrations of NaCl Brines (5500-200,000 mg/l), treated sea water, Wasia water, and 100,000 (mg/l) synthetic Arab-D water were used as displacement fluids.

As a result of this study , it was found that oil recovery increases as the injected water salinity increases up to 100,000 (mg/l). Increasing the salinity beyond 100,000 (mg/l) did not give a significant increase in oil recovery. The increase in oil recovery was found to be supported by a decrease in the IFT as a function of water salinity up to 100,000 (mg/l), where the IFT started to increase slightly beyond this salinity. The realtive permeability ratio (Kro/Krw) was found to increase as the injected water salinity increases.

The Compatibility tests conducted showed that when connate Arab-D water was mixed with sea water at 90°C ,calcium sulphate precipitated. However, analysis of the coreflooding effluents did not show any incompatibility problems due to injection of Wasia, and sea waters .

MASTER OF SCIENCE DEGREE

KING FAHD UNIVERSITY OF PETROLEUM AND MINERALS
Dhahran, Saudi Arabia

Date: May 1990

# CHAPTER 1

# Chapter 1

## INTRODUCTION

Waterflooding has been accepted worldwide as a reliable and economic recovery technique in reservoirs containing light and medium crude oil. Many oil fields that do not have a strong natural water drive are candidates for water flooding [1].

During the early days of waterflooding, only the quantity not the quality of the water was given consideration. However, later on it was realized that the quality of the water was as important as the quantity. Several papers have been published in the literature about water quality [2-11]. A good quality water should be: (1) available in sufficient quantities; (2) free from suspended solids and organic matters; (3) compatible with formation water; and (4) chemically inactive with compounds and elements present in the injection system.

There are mainly two sources of water for waterflooding, aquifer water and sea water. The salinity of aquifer water varies from fresh water to salt water with more than 300,000 ppm total dissolved solids. The salinity of normal sea water is around 35000 ppm dissolved solids [2], however it varies from place to another. In Saudi Arabia, two aquifers, Wasia and Biyadh, have been used

for water injection. Water salinity of these aquifers varies from 5000 to 18000 ppm [2]. water from the oil-producing Arab-D reservoir has salinity of about 200,000 ppm. In addition to Wasia and Biyadh, sea water from the Arabian Gulf with salinity of about 57000 ppm has been used in Ghawar field since 1978. Analysis of Wasia, Sea and Arab-D waters are shown in Table 1.1. The analyses of these waters illustrate the high concentration of calcium, magnesium, and strontium in Arab-D water and the high concentration of sulphate in sea water which present a possible incompatibility problem.

In this study, the effect of injected water salinity on oil recovery will be investigated. The incompatibility of the injected waters (mainly Wasia and sea water) with Arab-D formation water will also be investigated. The aim of this study is to identify an optimal salinity that will give maximum oil recovery if it exists.

In the next chapter, the literature related to this study is reviewed. Apparatus and experimental procedures are presented in Chapter 3. The results of the study are presented and discussed in Chapter 4. Finally, summary, conclusions, and recommendations are presented in Chapter 5.

Table 1.1: ANALYSIS OF WASIA, SEA AND ARAB-D WATERS [16]

| | Low-Salinity Arab-D | High-Salinity Arab-D | Wasia | Seawater* |
|---|---|---|---|---|
| $Na^{+}$ | 29,680 | 51,187 | 1,504 | 18,043 |
| $Ca^{++}$ | 13,574 | 29,760 | 392 | 652 |
| $Mg^{++}$ | 1,575 | 4,264 | 66 | 2,159 |
| $Ba^{++}$ | 8 | 10 | 0 | 0 |
| $Sr^{++}$ | 557 | 1,035 | 5 | 11 |
| $HCO_3^{-}$ | 369 | 351 | 192 | 119 |
| $Cl^{-}$ | 73,861 | 143,285 | 2,577 | 31,808 |
| $SO_4^{--}$ | 404 | 108 | 700 | 4,450 |
| $CO_3^{-}$ | 0 | 0 | 0 | 27 |
| TDS, mg/l | 120,000 | 230,000 | 5,436 | 57,269 |

* Arabian Gulf

# CHAPTER 2

# Chapter 2

## LITERATURE REVIEW

There is a limited number of publications in the literature that studied the effect of injected water salinity on oil recovery. However, the compatibility of the injected water and formation water has been investigated to some extent. Most of the publications concentrated on the scaling effects on production systems and surface facilities.

Anderson, R.E. [12], stated that subsurface injection of water containing multivalent cations may react with underground brines to give massive precipitation of inorganic salts. The resulting blockage of underground strata may seriously impede flow.

Buck, J.R. [13], pointed out that precipitation of compounds due to incompatibility of the injected water is seldom of importance, since the deposited materials are layed down at a considerable distance from the point of injection and do not noticeably reduce the system permeability.

Bertero, L. et al. [14], evaluated quantitatively the permeability reduction caused by scale formation in reservoir rock pores. They designed a piece of equipment that enabled two water streams to be continuously mixed solely in the pores of a core sample. The two incompatible waters were simulated with diluted sodium sulphate. The

core sample (sandstone) was 100% saturated with reservoir brine and weighed. Reservoir brine and injection water were pumped simultaneously through the core at constant rates and at a constant ratio, and the differential pressure between the inlet and the outlet was measured. At regular intervals, the core sample was withdrawn and weighed to determine the amount of scale present in the pores. A set of curves showing permeability reduction versus the pore volume of scale formed was presented, and they are shown in Fig. 2.1. They also stated that "the standard practice in oil industry of evaluating injection water compatibility with reservoir brine by running waterflooding tests at reservoir conditions on cores previously saturated with reservoir brine is of limited values as only first contact phenomena are produced (no thermal effects on injection waters, nor multiple contact phenomena between injection water and reservoir brine). As a consequence, these tests should be considered only as a screening tool to evaluate different potential injection waters through comparison".

Mungan, N. [15], found from laboratory studies that permeability reduction occurred when the injected water is less saline than the connate water as a result of clay expansion. He also found that the permeability damage can be caused by changes in the pH of the injected water.

Mitchel et al. [4], performed an experiment to study the effect of incompatibility of injected water and formation water. They used a core

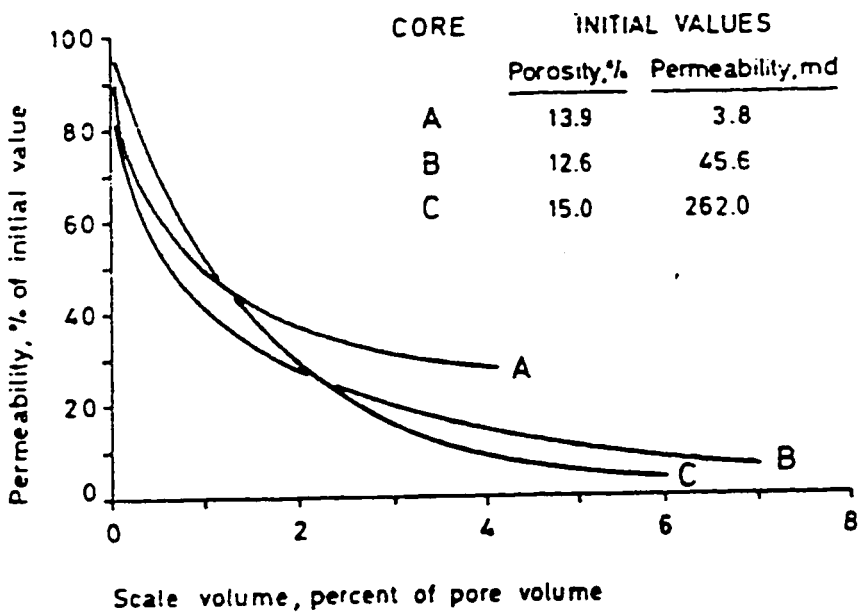


Fig. 2.1 : Permeability reduction as a function of the amount of scale precipitated in the pores (14)

with six side injectors at one end and one outlet at the other end to simulate a production well. The experimental set-up is shown in Fig. 2.2. The flow rate was kept constant with a ratio of injected water to formation water = 1/10. They found that the injection pressure remained constant and then increased rapidly just before the core became completely blocked. They stated that scale deposition occurred around the surfaces of the pores, as more scale was deposited, the pore-throat flow area was reduced.

Lindlof and Stoffer [16], made a study of sea water injection incompatibility in Saudi Arabia. The laboratory tests performed showed no measurable reduction in permeability as a result of incompatibility effects between Arab-D formation water and sea water when the two waters mix in the pore channels during displacement of one water by the other. They reported that mixing of Arab-D water with sea water in various proportions demonstrated that strontium sulfate could be precipitated.

Bernard, G.G. [13], performed laboratory experiments where the injected water was incompatible with connate water. He found that different waters do not mix very much in the reservoir.

Cooke, C.E. et al. [17], studied the effect of the injected water salinity on oil recovery for alkaline waterflooding. In their study they performed the flooding experiments with different salinity alkaline

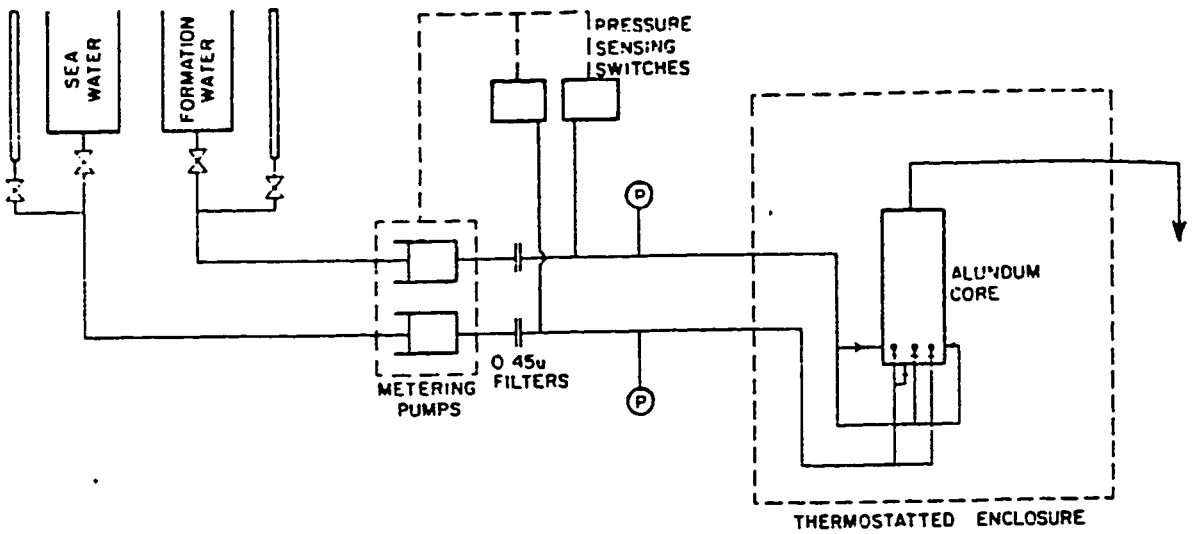


Fig. 2.2 : Experimental Set-Up used in Mitchel et al Study (4).

waters ($NaCO_3$ is added to the salt water to increase pH), temperatures were 77 °F and 112 °F, porous medium was No. 16 Ottawa sand, connate water was 5.8% NaCl, and synthetic and crude oil. They found that oil recovery increased with increasing salinity of injected water, until it came to a point where any increase in injected water salinity will result in a decrease in recovery. This point depended on pH of the injected water and oil composition. Their results are shown in Figs. 2.3 and 2.4.

Omar, A.E. et al. [18],studied the effect of formation damage , due to injection of high salinity brines, and temperature on relative permeabilities to oil and water. they used unfired Berea sandstone cores saturated with high salinity Arab-D water. The displacing brine concentration was varied from 0.6 to 15.0% NaCl. They found that the relative permeability to oil decreased , and the relative permeability to water increased with NaCl concentration due to dislodgment and movement of clay particles within the cores. They also found that the residual oil saturation increased with both the concentration of NaCl and temperature.

It can be Inferred from the literature review that there is a limited literature about the effect of injected water salinity on oil recovery and a controversy about the effect of injecting incompatible waters on oil recovery. Therefore, the objectives of this study are : (1) to investigate the effect of injected water salinity on oil recovery; (2) to

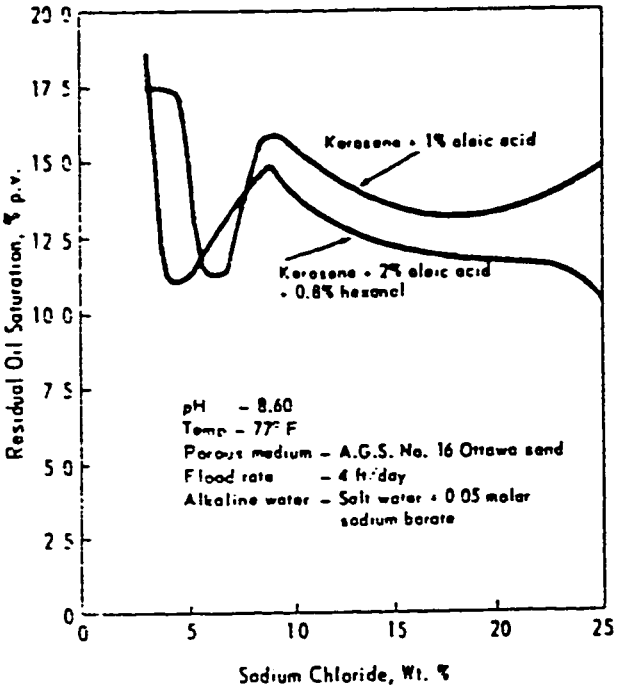


Fig. 2.3 : Effect of Flood Water Salinity on Recovery of Synthetic Acidic Oil by Alkaline Waterflooding (17).

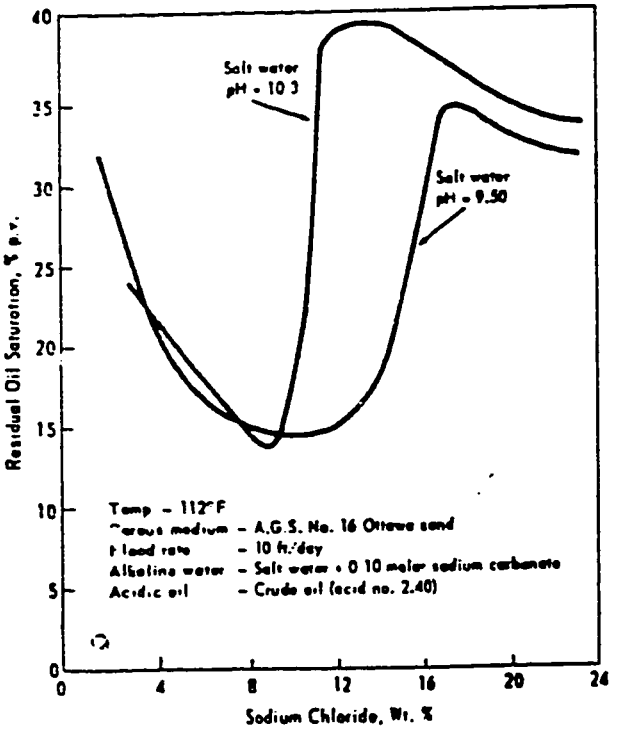


Fig. 2.4 : Effect of Flood Water Salinity on Recovery of Crude Oil by Alkaline Waterflooding (17).

investigate the effect of incompatibility of sea water and Wasia water with formation Arab-D water on oil recovery.

# CHAPTER 3

# Chapter 3

# EXPERIMENTAL PROCEDURE

Core flooding experiments were performed under reservoir conditions using water with different salinities. The following sections describe the material, apparatus, experimental procedures, and properties of the fluids used.

## 3.1 MATERIAL

### 3.1.1 Porous Medium

One-foot composite Berea sandstone cores (two-pieces) were used in all the flooding experiments. The cores had a porosity ranging from 22.97% to 24.64%, and a permeability ranging from 565 to 728 md. The diameter of the cores ranged from 2.47 to 2.51 cm. All the cores were fired at 900 °C for 18 hours in an electric furnace to stabilize the clay content of the cores. Table 3.1 shows the physical properties of all the core samples used. Scanning Electron Microscope Analysis of one fired core sample showed the core to be highly porous and consists mainly of quartz crystals and clay particles as shown in Fig. 3.1 and Fig. 3.2. The energy dispersive spectrum (EDS) of the clay particles showed the presence of mainly aluminum and silicon.

**Table 3.1**

**Physical Properties of Berea Cores used in this Study**

| Core # | Length (cm) | Diameter (cm) | Porosity (% P.V.) | Abs. Perm. (md) | Swi (% P.V.) |
|---|---|---|---|---|---|
| 1 | 14.20 | 2.47 | 23.42 | 607 | 15.41 |
| 2 | 14.70 | 2.47 | 23.71 | 615 | 16.39 |
| 3 | 14.70 | 2.51 | 23.37 | 579 | 15.48 |
| 4 | 14.35 | 2.51 | 23.36 | 572 | 14.98 |
| 5 | 14.55 | 2.50 | 22.97 | 565 | 14.44 |
| 6 | 14.55 | 2.50 | 22.97 | 655 | 14.49 |
| 7 | 14.10 | 2.48 | 23.34 | 566 | 15.39 |
| 8 | 13.45 | 2.48 | 23.30 | 571 | 15.25 |
| 9 | 14.10 | 2.51 | 24.64 | 630 | 13.78 |
| 10 | 15.00 | 2.51 | 24.30 | 728 | 13.73 |
| 11 | 12.90 | 2.50 | 24.38 | 647 | 13.64 |
| 12 | 17.80 | 2.50 | 24.52 | 672 | 13.60 |
| 13 | 12.80 | 2.51 | 24.23 | 636 | 14.29 |
| 14 | 15.05 | 2.51 | 24.11 | 691 | 14.70 |

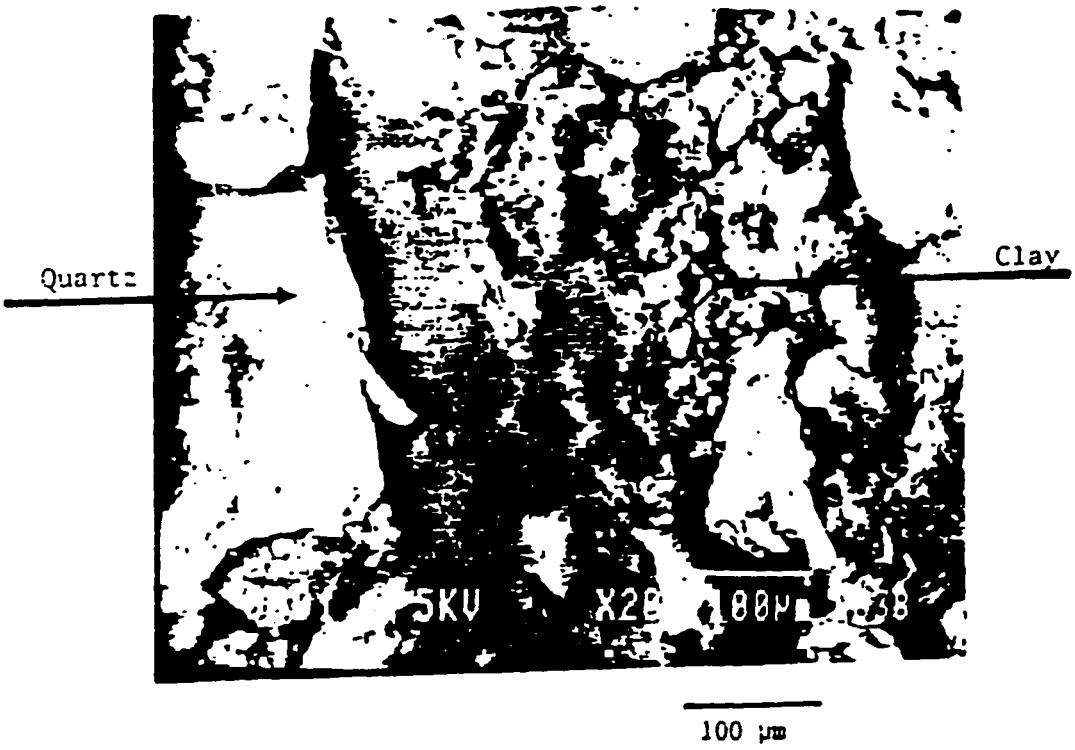


Fig. 3.1: Scanning Electron Microscope Photo of the Fired Berea Core Sample.

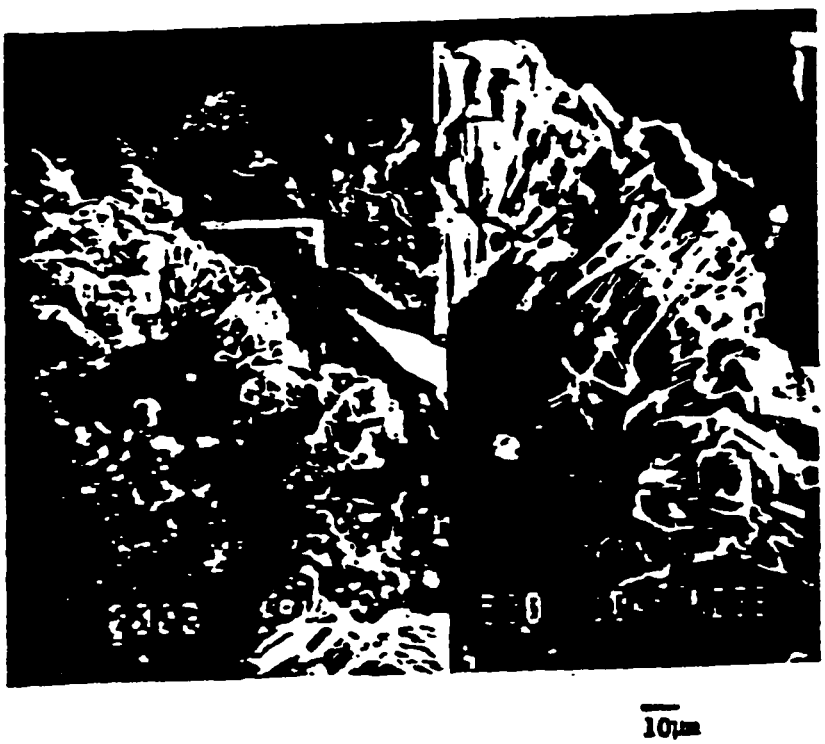


**Fig. 3.2: Magnification of the Clay Particles in the Fired Berea Core Sample.**

### 3.1.2 Oil

The oil used in all the flooding experiments was a dead Arabian Light crude oil with a density of 0.839 gm/cc and a viscosity of 2.48 cp at 23 °C and atmospheric pressure. The oil was filtered through a 2.5 μ filter before using in the experiments.

### 3.1.3 Brines

Five different types of brines were used in this study. They are described below:

1. Different concentration sodium chloride (NaCl) solutions (prepared using distilled water and pure sodium chloride) were used as injection brines in the NaCl brine runs. These concentrations were 0.55%, 1.5%, 3.0%, 6.0%, 10.0%, and 20%. The 20% brine was used also as connate water.
2. Actual Wasia water obtained from the field was used as injection brine.
3. Actual Sea water obtained from Qurrayah Sea Water Treatment Plant was used as injection brine.
4. 100,000 (mg/l) synthetic high salinity Arab-D water was used as injection brine.
5. Synthetic high salinity Arab-D water (230,000 mg/l) was used as connate water in the experiments where Wasia water, Sea water, or 10% Arab-D waters were injected.

A special preparation procedure recommended by American Petroleum Institute (API) was followed to prepare the high salinity Arab-D water. This procedure is summarized below:

1. The weights of the chemicals to be used to formulate the water were calculated using the analysis shown in Table 1.1. The calculated weights are shown in Table 3.2.
2. Carbon dioxide ($CO_2$) was bubbled into distilled water for 30 minutes before using.
3. Sodium bicarbonate ($NaHCO_3$) and sodium sulfate ($Na_2SO_4$) were dissolved in distilled water and added to the preparation container.
4. Sodium chloride (NaCl), strontium chloride ($SrCl_2$), and barium chloride ($BaCl_2$), were then dissolved in distilled water and added to the container respectively.
5. Calcium chloride ($CaCl_2$) and magnesium chloride ($MgCl_2$) were added last. Hydrated $CaCl_2$ and $MgCl_2$ were not oven-dried because they lose their water of crystallization. The chemicals were dissolved and added to the container.

After all the additions were made, and the volume adjusted, the contents of the container were agitated for 30 minutes by bubbling $CO_2$, and then the container was closed.

Table 3.2

Calculated Weights of Chemicals Required to Prepare 1.0 Liter of High Salinity Arab-D Water

| Chemical | Weight (gm) |
|---|---|
| NaCl | 129.614 |
| $CaCl_2$ | 82.404 |
| $MgCl_2$ | 16.670 |
| $SrCl_2$ | 0.0152 |
| $BaCl_2$ | 1.873 |
| $NaHCO_3$ | 0.483 |
| $Na_2SO_4$ | 0.160 |

### 3.1.3.1 Fluid System Properties

#### (1) Viscosity

The viscosities of different NaCl concentration brines, wasia water, sea water, 10% synthetic Arab-D water, and oil were measured using a low range model LVTDCP Brookfield viscometer. Figure 3.3 shows viscosity vs. salinity of brines at 90°C.

#### (2) Density

The densities of different waters and oil were measured at 90°C using DMA 60 digital density meter. The densities at room temperature (23°C) of connate waters were measured with a pycnometer. Both 20% NaCl and high salinity Arab-D waters had a density of 1.14 gm/cc. Figure 3.4 shows density vs. salinity of brines at 90°C.

#### (3) pH

pH values of the brines used in this study were measured with Fisher Accumet pH meter model 805 MP. Figure 3.5 shows how pH varies with water salinity.

#### (4) Interfacial Tension

The pendent drop method was used to measure the interfacial tension (IFT) between oil and different brines at 90°C and atmospheric pressure. Figure 3.6 shows how IFT varies with brine salinity.

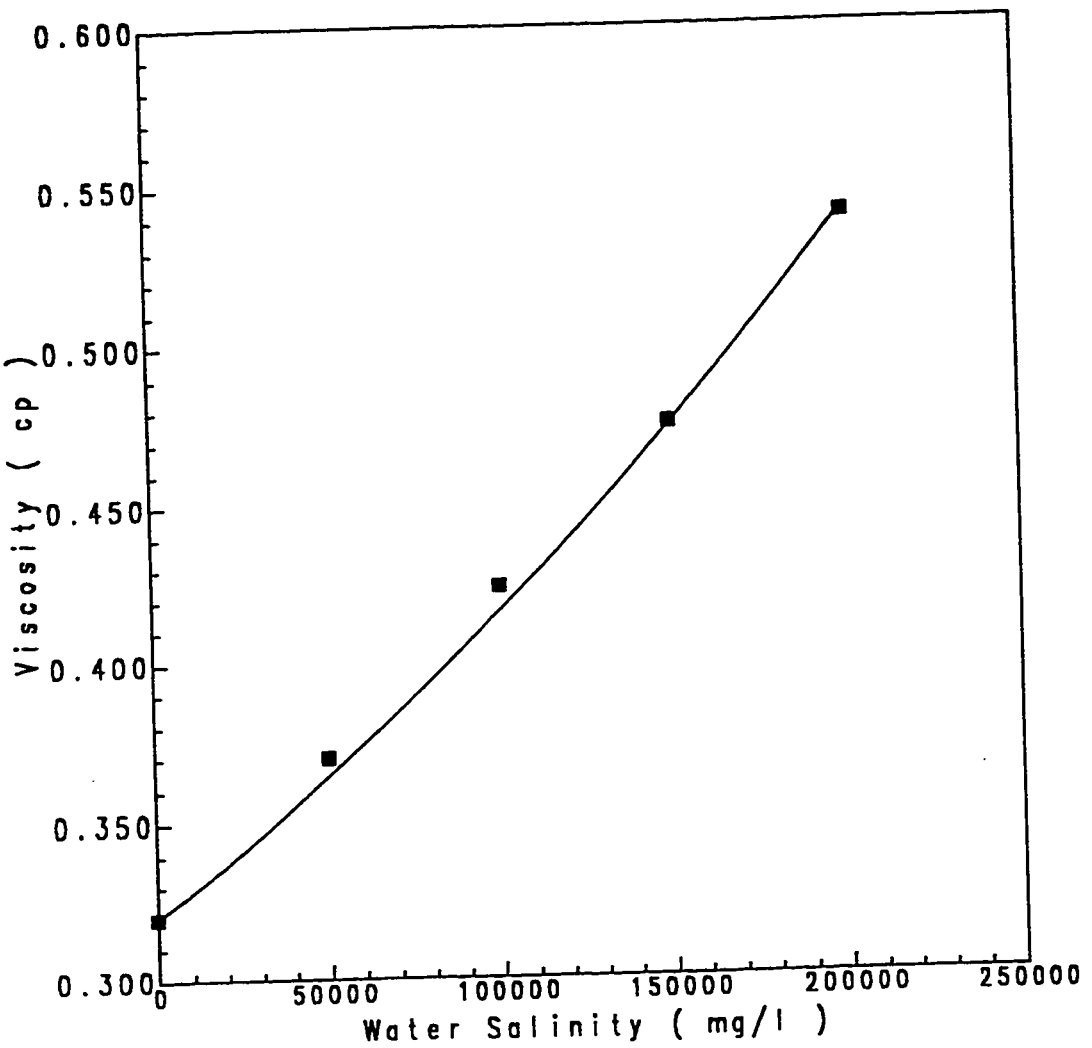


Fig. 3.3 - Effect of Water Salinity on Viscosity @90 °C for NaCl Brines

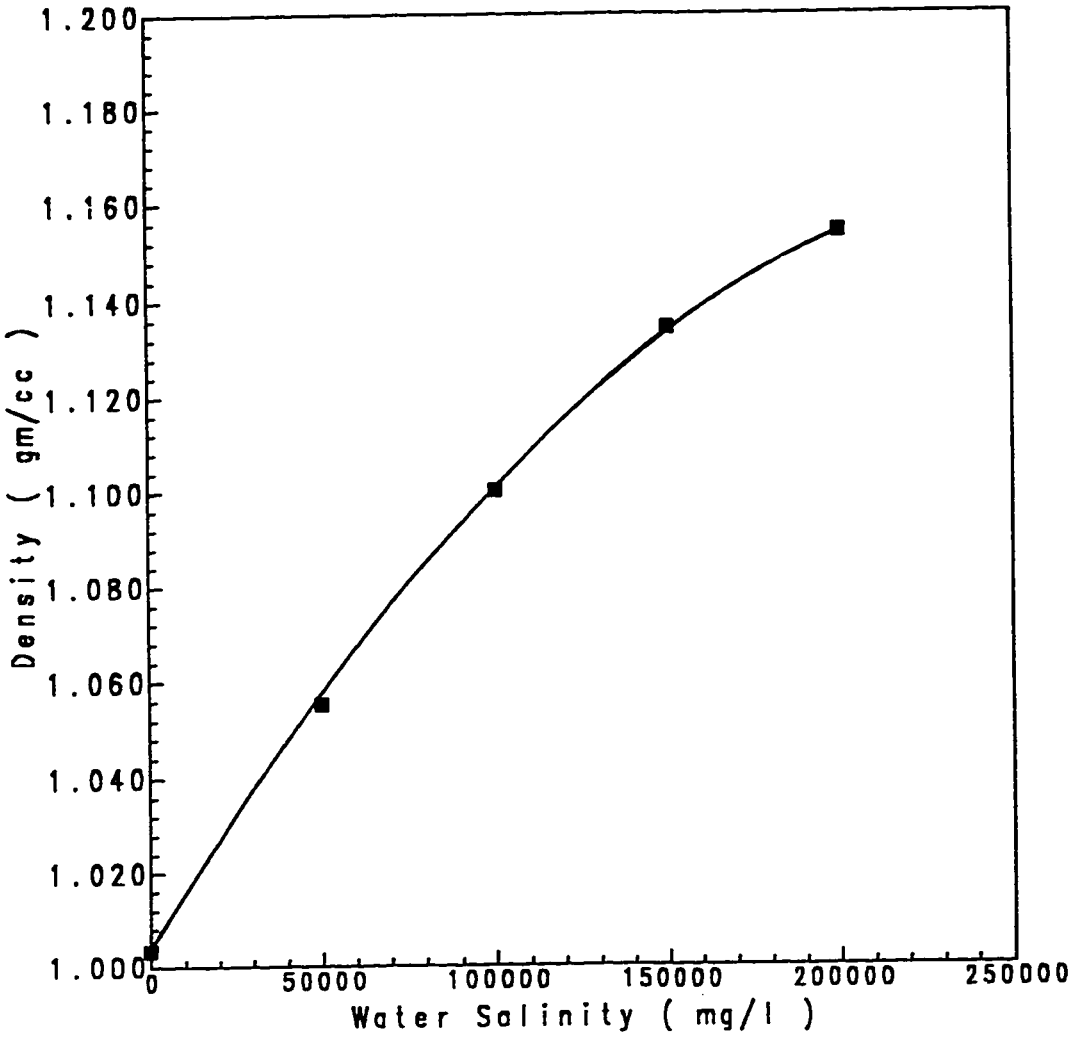


Fig. 3.4 - Effect of Water Salinity on Density @ 90 °C for NaCl Brines

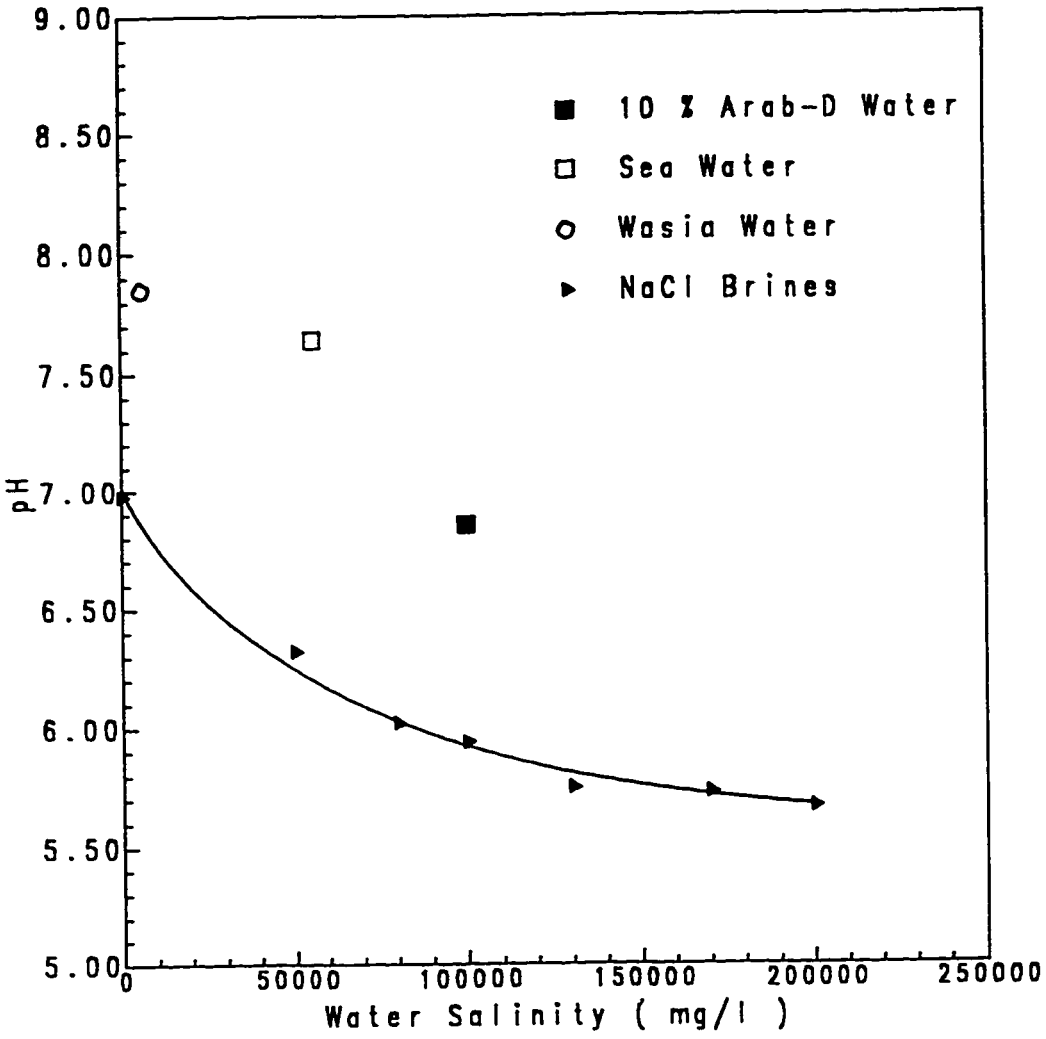


Fig. 3.5 - Effect of Water Salinity on pH @ 23 °C

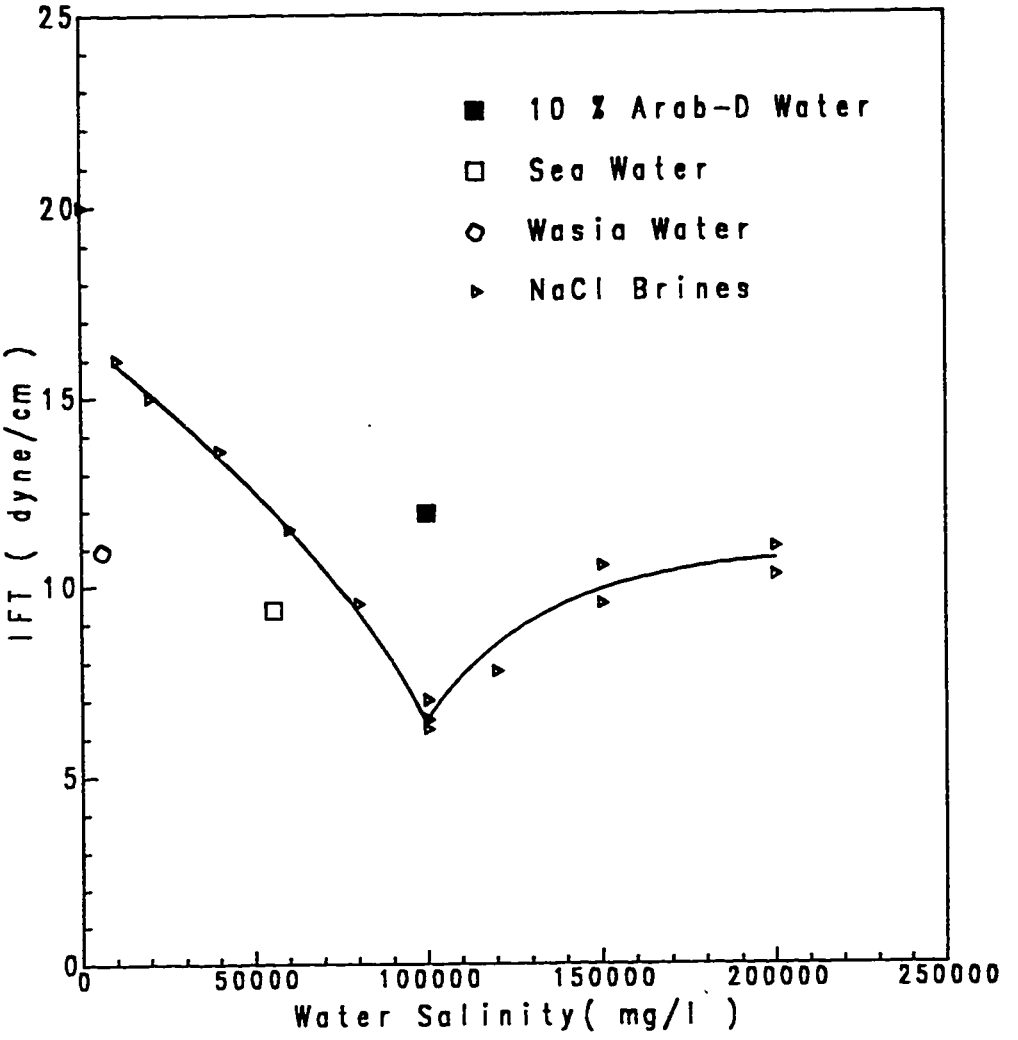


Fig. 3.6 - Effect of Water Salinity on IFT @ 90 °C

### (5) Resistivity

The resistivities of the produced waters in the NaCl brine runs where different NaCl concentration brines were injected, were measured using a Core Lab. Model CEF resistivity meter with Fisher ABS plastic dip-type conductivity cell. A reference curve showing resistivity vs. salinity using this device is shown in Fig. 3.7.

### (6) Water Analysis

The analysis for anions and cations of the produced waters in the runs, where wasia, sea, and 10% synthetic Arab-D waters were injected were done by inductively coupled plasma (ICP) method. The analyses of wasia, sea, 10% synthetic Arab-D waters, and high salinity Arab-D water are shown in Table 3.3.

Table 3.4 shows the viscosities, pH and density at 90°C of all brines used in this study.

## 3.2 APPARATUS

A schematic of the experimental apparatus used in this study is shown in Fig. 3.8. It consisted mainly of two constant rate displacement pumps, two transfer cells, a core holder, an oven, a differential pressure measurement and a recording system, fraction collector, back pressure multiplier, and a back pressure regulator. A brief description of each component follows.

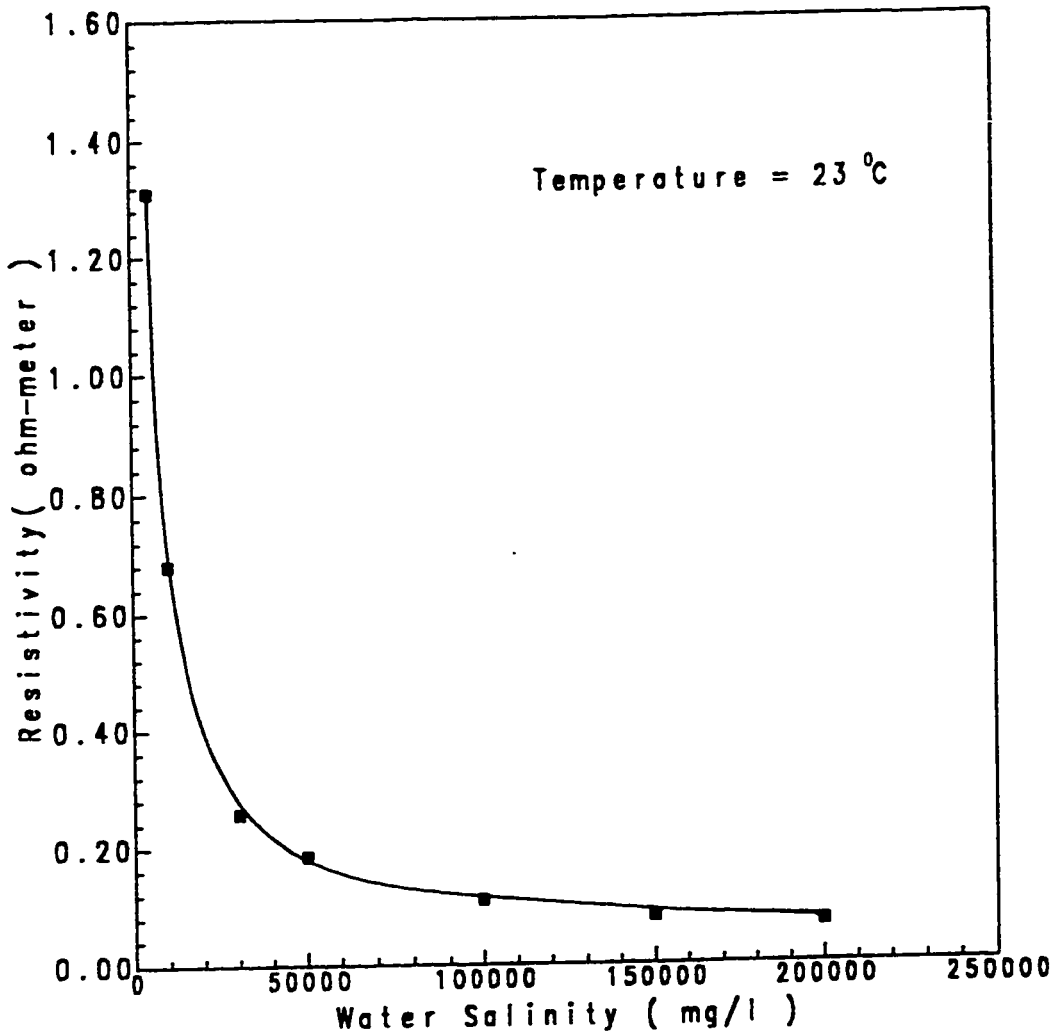


Fig. 3.7 - Effect of Water Salinity on Resistivity for NaCl Brines

Table 3.3

Analysis of Waters Used in the Study Using ICP Method

| | High-Salinity Arab-D | 10% Arab-D | Sea Water | Wasia Water |
|---|---|---|---|---|
| $Na^{+}$ | 51780 | 22840 | 17260 | 1320 |
| $Ca^{++}$ | 29300 | 12580 | 615 | 570 |
| $Mg^{++}$ | 4145 | 1815 | 2035 | 102 |
| $Ba^{++}$ | 12.4 | 3.3 | 0 | 0 |
| $Sr^{++}$ | 990 | 440 | 9.5 | 8.8 |
| $HCO_3^{-}$ | 163.7 | 23.7 | 144.1 | 178.5 |
| $Cl^{-}$ | 145100 | 63730 | 31380 | 2784 |
| $SO_4^{--}$ | 83 | 47 | 4180 | 1090 |
| TDS mg/l | 231574 | 101479 | 55623.6 | 6053.3 |

**Table 3.4**

**Properties of Brines Used in this Study**

| Brine | Viscosity (cp) @ 90 °C | pH @ 23 °C | Density (gm/cc) @ 90 °C |
|---|---|---|---|
| 0.55% NaCl | 0.330 | 6.88 | 1.009 |
| 1.5 % NaCl | 0.340 | 6.68 | 1.020 |
| 3.0 % NaCl | 0.354 | 6.47 | 1.036 |
| 6.0 % NaCl | 0.386 | 6.18 | 1.066 |
| 10 % NaCl | 0.424 | 5.93 | 1.1002 |
| 20 % NaCl | 0.540 | 5.57 | 1.154 |
| Wasia Water | 0.335 | 7.85 | 1.0053 |
| Sea Water | 0.382 | 7.64 | 1.0632 |
| 10 % Arab-D | 0.430 | 6.85 | 1.1023 |

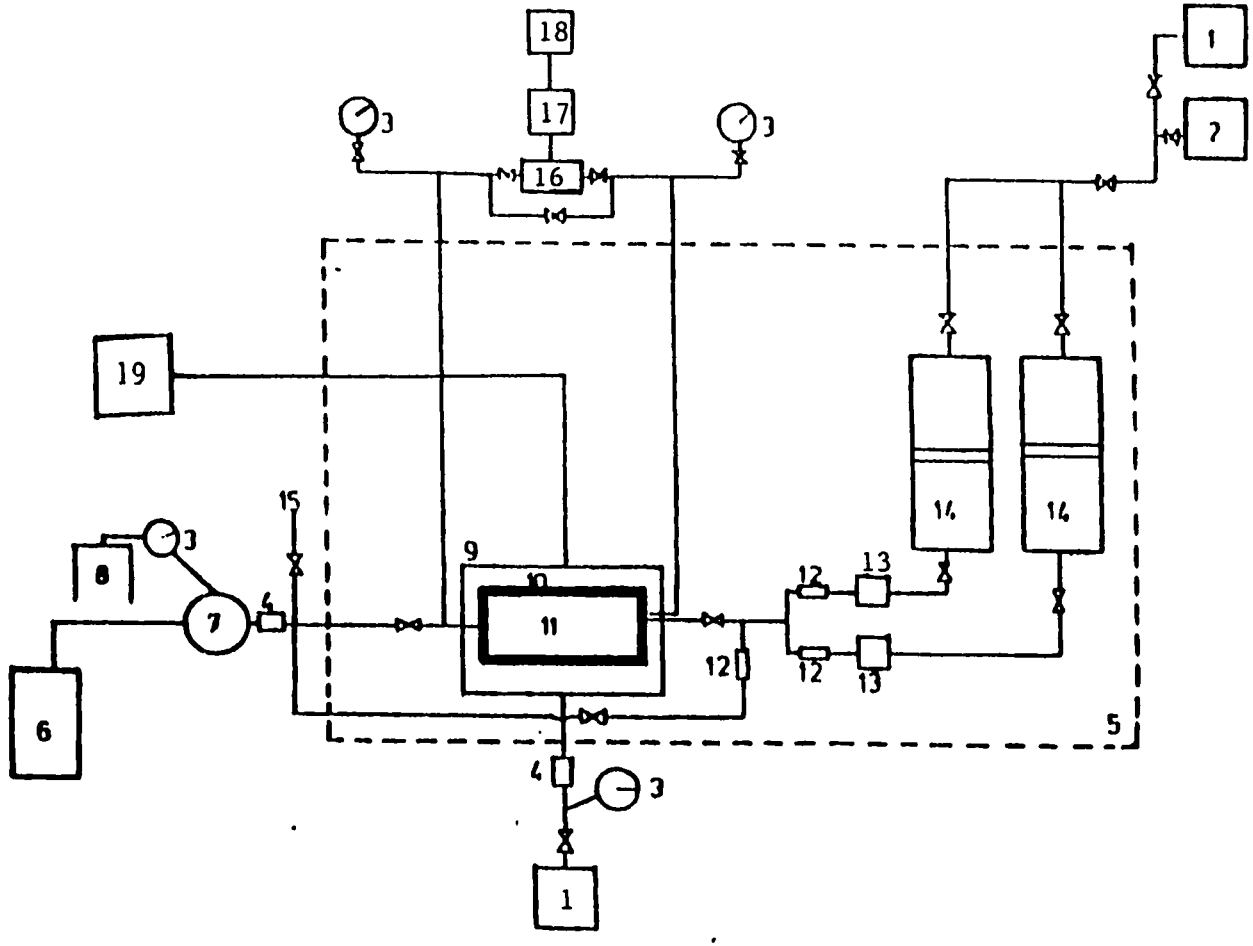


Fig. 3.8 : Schematic Diagram of Core Flooding Set-Up

1. Mineral Oil Reservoir
2. Pumps
3. Pressure Gauge
4. Safety Valve
5. Oven
6. Fraction Collector
7. Back Pressure Regulator
8. Pressure Cylinder
9. Core Holder
10. Rubber Sleeve
11. Core Sample
12. Check Valve
13. Filter
14. Transfer Cell
15. Drainage Valve
16. Differential Pressure Transducer
17. Read Out
18. Chart Recorder
19. Pressure Multiplier

### 3.2.1 Core Holder

A Hassler type stainless steel core holder, designed for consolidated core samples up to 31 cm in length and 2.54 cm in diameter was used. It can withstand pressures up to 10,000 psi.

### 3.2.2 Transfer Cells

Two stainless steel transfer cells with a pressure rating of 5000 psi, manufactured by Core Lab. Inc., were used to inject the fluids into the core holder. They have a capacity of 1000 cc, and a free piston which separates the two fluids inside. The injection fluids (brine or oil) were displaced from the proper transfer cell into the core using the constant rate pump.

### 3.2.3 Pumps

(a) During the displacement experiments, two constant rate (Varian Model 2010) pumps, with a pressure limit of 7350 psi and a maximum rate of 10 cc/min were used.

(b) Confining pressure was applied using a hand pump manufactured by Core Lab. Inc.

### 3.2.4 Pressure Measurement System

The differential pressure across the core during displacement experiments was measured using a Validyne Model DP 303-66 pressure transducer. The working range of the transducer can be varied by

using different diaphragms. The pressure transducer was connected to a Validyne Model CD23 digital indicator. The output was recorded by a Soltec model 1243 strip-chart recorder. The pressure transducer with the appropriate diaphragm was calibrated using either a dead weight tester, or a pressure gauge calibrated by a dead weight tester. Before using the transducer, bleed ports were bled off to insure completely liquid filled cavities of the diaphragm.

### 3.2.5 Back Pressure Regulator

A dome loaded back pressure regulator, manufactured by Temco was used to apply constant back pressure during the experiments. Its pressure limit is 5000 psi.

### 3.2.6 Back Pressure Multiplier

A back pressure multiplier operating with mineral oil manufactured by Core Lab. Inc. was used to provide high back pressure from a low pressure source (low pressure nitrogen cylinder).

### 3.2.7 Fraction Collector

An ISCO time controlled fraction collector was used. It can accommodate 100 graduated glass tubes of 10 cc. Volume with appropriate racks.

### 3.2.8 Rubber Sleeve

The composite core was placed in a viton rubber sleeve during the runs. It has 2.54 cm inner diameter and can withstand temperatures up to 350 °F.

### 3.2.9 Oven

The core holder and transfer cells were placed in a temperature controlled oven manufactured by Dispatch. This model LDB has a temperature range of 275 °C and two ducts at the sides to allow tubings to enter or leave the oven.

### 3.2.10 Auxiliary Equipment

Other equipments used in the displacement tests were filters, pressure gauges, stainless steel tubings and fittings, valves, vacuum oven, vacuum pump, and a balance.

## 3.3 PROCEDURES

### 3.3.1 Porosity Measurement

The porosity of the core samples was measured with the saturation method. The cores were placed in a big flask and evacuated for about four hours. Then, the connate water, either syntyetic high salinity Arab-D water or 20% NaCl brine, was introduced to saturate the cores through a valve on the top of the flask, while the evacuation was

continuing. Porosities were determined from the weights of saturated and dry cores, dimensions of the cores, and connate water density. Porosities of all cores are shown in Table 3.1.

### 3.3.2 Absolute Permeability Measurement

After measuring the porosity of the core sample, the core was loaded in the rubber sleeve. After assembling the core holder, the annulus between the rubber sleeve and the core holder body was pressurized with the hand pump to the confining pressure (1700 psi). The absolute permeability was measured by flooding the core with 20% NaCl brine, at room temperature. Different flow rates were used and the differential pressure was recorded to enable the calculation of absolute permeability using Darcy's law. Table 3.1 shows the absolute permeabilities of the cores used.

### 3.3.3 Irreducible Water Saturation Determination

After measuring the absolute permeabilities, the cores were centrifuged in DAMON/IVEC model DPR-6000 centrifuge machine at 3500 rpm for one hour, in order to achieve an irreducible water saturation (Swi) of approximately 15%. Special cups were fabricated to accommodate core samples of 15.0 cm length. Swi values were calculated knowing the core dry weight, weight after centrifuging, pore volume of the core, and brine density. Values of Swi of all the cores are shown in Table 3.1.

### 3.3.4 Core Preparation And Loading

Two centrifuged samples were wrapped with a layer of plastic and a layer of teflon tape, to hold the cores firmly as one core, and to make sure that no gap exists between the composite core and the rubber sleeve. Next, the composite core was placed in the rubber sleeve. The end plugs were inserted into each end of the sleeve and were pressed against the core sample by a retaining screw which threads through the end caps. When the composite core length was less than 31 cm, stainless steel spacers were placed in the gap between the end plugs and the retaining screws. Finally, the core holder caps were fixed.

### 3.3.5 Oil Saturation

After loading the core into the core holder, the annulus between the rubber sleeve and the body of the core holder was pressurized with mineral oil through the body port to 1700 psi confining pressure. Next, the inlet of the core holder was connected to a vacuum pressure gauge, while the outlet was connected to the vacuum pump by means of a transparent tygon hose. The core and dead lines were vacuumed at room temperature until a pressure of -29" Hg was attained. The valve at the inlet was then closed and the vacuum pressure gauge was disconnected. A burette full of oil was connected to the inlet, the valve was opened, and oil was introduced from the burette to the core.

Vacuuming was continuing until the first drop of oil appeared in the outlet transparent hose. The valve at the outlet was then closed and the vacuum pump disconnected. The valve at the inlet was kept open for several hours until no drop of the oil level in the burette was observed. Finally, the volume of oil retained by the core was calculated, knowing the total pore volume, and irreducible water volume. This oil volume was considered as the initial oil in place (IOIP).

### 3.3.6 Flooding Experiments

After saturating the core with oil, the core holder was assembled in the oven as shown in Fig. 3.8. The system was then heated to 90 °C and left overnight for temperature equilibration. The back pressure was set to 200 psi. Then, the effective permeability to oil was measured by injecting oil at different flow rates and measuring the differential pressure across the core. Next, the oil valve was closed and the brine flooding was started. A constant flow rate of 30 cc/hr was kept constant through the experiments. Flooding continued until no more oil was produced. Meanwhile, the differential pressure was recorded continuously by the chart recorder. The effluent was collected in graduated tubes in the fraction collector. At the end of the flood, the effective permeability to the injected brine was determined by measuring the differential pressure across the core at different flow rates.

### 3.3.7 Core Cleaning

At the end of each run distilled water was injected into the core to displace the salt water in the core. The composite core was taken out of the core holder and placed in a soxhlet unit. The cores were cleaned with toluene for several days. Next, the cores were cleaned with isopropyl alcohol for three days to restore the wettability.

# CHAPTER 4

# Chapter 4

# RESULTS AND DISCUSSION

Unsteady state displacement experiments using Berea sandstone core samples were performed to study the effect of injected water salinity on oil recovery. Different concentrations of NaCl brines were used in the first six experiments, and actual waters (sea, Wasia and 100,000 mg/l Arab-D) were used in the last three experiments. Besides studying oil recovery in the actual water runs, the compatibility of the three waters with connate Arab-D water was investigated. A summary of fluid and core properties that were used in all the runs is shown in Table 4.1. The raw experimental data of all the runs is shown in Appendix A.

The results of the experiments are presented and discussed in the following sections.

## 4.1 OIL RECOVERY

### 4.1.1 Displacement Runs Using NaCl Brines

Oil recovery as a function of cumulative water injected for Runs No. 1 through 6 where different concentrations of NaCl brines were injected is shown in Fig. 4.1. The breakthrough recovery and recovery at the end of the run of the six runs are summarized in Table

## Table 4.1

## Summary of Fluid and core Properties for All the Runs

| Run # | Injected Water Salinity (mg/l) | Cores Used | L (cm) | D (cm) | Porosity (%) | Kabs (md) | Swi (%) | $\mu_w$ (cp) | IFT (dyne/cm) |
|---|---|---|---|---|---|---|---|---|---|
| 1 | 5500 NaCl | 1+2 | 28.9 | 2.47 | 23.56 | 610.40 | 15.91 | 0.33 | 16.0 |
| 2 | 15000 NaCl | 3+4 | 29.5 | 2.51 | 23.37 | 575.38 | 15.23 | 0.34 | 14.5 |
| 3 | 30000 NaCl | 5+6 | 29.1 | 2.50 | 22.97 | 606.26 | 14.49 | 0.354 | 13.8 |
| 4 | 60000 NaCl | 1+2 | 28.1 | 2.47 | 23.29 | 610.10 | 15.59 | 0.384 | 11.5 |
| 5 | 100000 NaCl | 7+8 | 27.55 | 2.48 | 23.35 | 568.40 | 15.32 | 0.424 | 6.5 |
| 6 | 200000 NaCl | 5+6 | 28.34 | 2.50 | 22.97 | 606.26 | 15.72 | 0.540 | 10.8 |
| 7 | 55624 Sea Water | 9+10 | 29.10 | 2.51 | 24.46 | 676.91 | 13.75 | 0.382 | 9.35 |
| 8 | 6053 Wasia | 11+12 | 30.70 | 2.51 | 24.45 | 661.08 | 13.57 | 0.335 | 10.92 |
| 9 | 100000 Arab-D | 13+14 | 27.85 | 2.51 | 24.16 | 664.58 | 14.51 | 0.430 | 11.91 |
| R-6 | 200000 NaCl | 10+11 | 27.12 | 2.51 | 23.14 | 547.5 | 14.12 | 0.540 | 10.8 |
| R-7 | 55624 Sea Water | 15+16 | 29.25 | 2.42 | 23.44 | 676.12 | 14.45 | 0.382 | 9.35 |

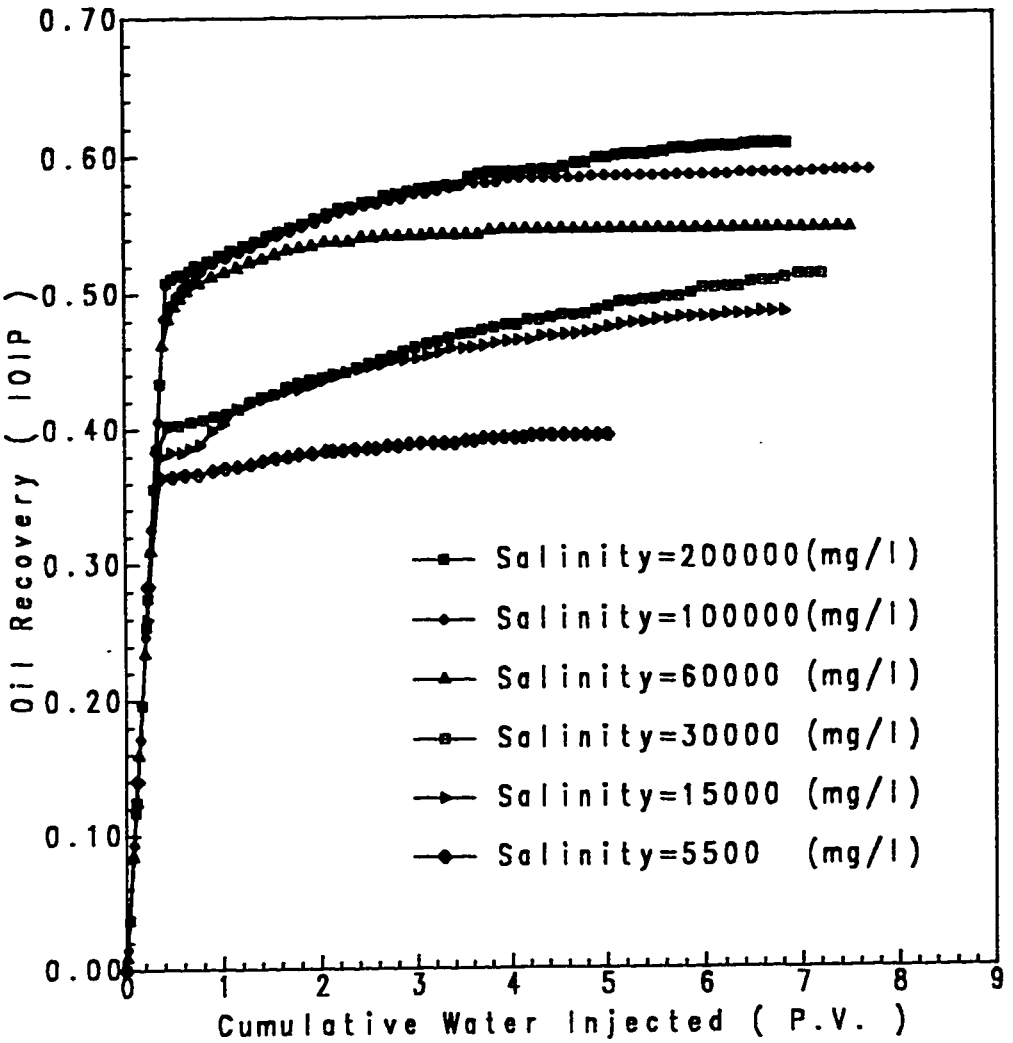


Fig 4.1 - Oil Recovery vs. Water Injected for NaCl Brine Runs

4.2. The table shows that, in general, both breakthrough recovery and recovery at the end of the run increase with increasing injected water salinity. All the runs are characterized by little oil production after breakthrough. Run # 3 has the maximum difference between breakthrough recovery and recovery at the end of the run (10.92% IOIP) while Run # 1 has the minimum (3.10% IOIP).

Table 4.3 shows the analysis of breakthrough recovery. It can be inferred from this table and Fig. 4.2 that breakthrough recovery increased significantly with increasing injected water salinity up to 60,000 mg/l NaCl. Increasing the injected water salinity beyond 60,000 mg/l did not increase breakthrough recovery significantly.

Since the runs were not terminated at the same number of pore volumes (P.V.) injected, the recoveries at the end of the runs are not appropriate for comparison purposes. Instead, the oil recovery after injecting 5.0 P.V. was chosen for comparison among the runs. Table 4.4 shows the analysis of oil recovery after injecting 5.0 P.V. It is noticed that when the injected water salinity increased, recovery increased. The difference in oil recovery between runs decreased as the injected water salinity increased as shown in Fig. 4.3.

### 4.1.2 Displacement Runs Using Actual Waters

Three actual waters were used in this study. These are Wasia, sea and 100,000 mg/l Arab-D waters. Oil recovery as a function of

## Table 4.2

## Breakthrough and End of Run Recoveries for NaCl Brine Runs

| Run # | NaCl Concentration (mg/l) | IFT (dyne/cm) | $\frac{\mu_o}{\mu_w}$ | B.T.Recovery (% IOIP) | Recovery at the end of the run (% IOIP) | Difference Between B.T. and End of Run Recoveries (% IOIP) |
|---|---|---|---|---|---|---|
| 1 | 5,500 | 16.0 | 5.58 | 36.43 | 39.53 | 3.10 |
| 2 | 15,000 | 14.5 | 5.41 | 37.93 | 48.40 | 10.47 |
| 3 | 30,000 | 13.8 | 5.20 | 40.24 | 51.16 | 10.92 |
| 4 | 60,000 | 11.5 | 4.79 | 48.08 | 54.58 | 6.50 |
| 5 | 100,000 | 6.5 | 4.34 | 49.13 | 58.77 | 9.64 |
| 6 | 200,000 | 10.8 | 3.41 | 50.79 | 60.75 | 9.96 |

## Table 4.3

## Analysis of Breakthrough Recovery for NaCl Brine Runs

| Run # | NaCl Concentration (mg/l) | IFT (dyne/cm) | $\frac{\mu_o}{\mu_w}$ | Breakthrough Recovery (% IOIP) | Increase From Run#1 (% IOIP) | Difference Between Successive Runs (% IOIP) |
|---|---|---|---|---|---|---|
| 1 | 5,500 | 16.0 | 5.58 | 36.43 | -- | -- |
| 2 | 15,000 | 14.5 | 5.41 | 37.93 | 1.50 | 1.50 |
| 3 | 30,000 | 13.8 | 5.20 | 40.24 | 3.81 | 2.31 |
| 4 | 60,000 | 11.5 | 4.79 | 48.08 | 11.65 | 7.84 |
| 5 | 100,000 | 6.5 | 4.34 | 49.13 | 12.70 | 1.05 |
| 6 | 200,000 | 10.8 | 3.41 | 50.79 | 14.36 | 1.66 |

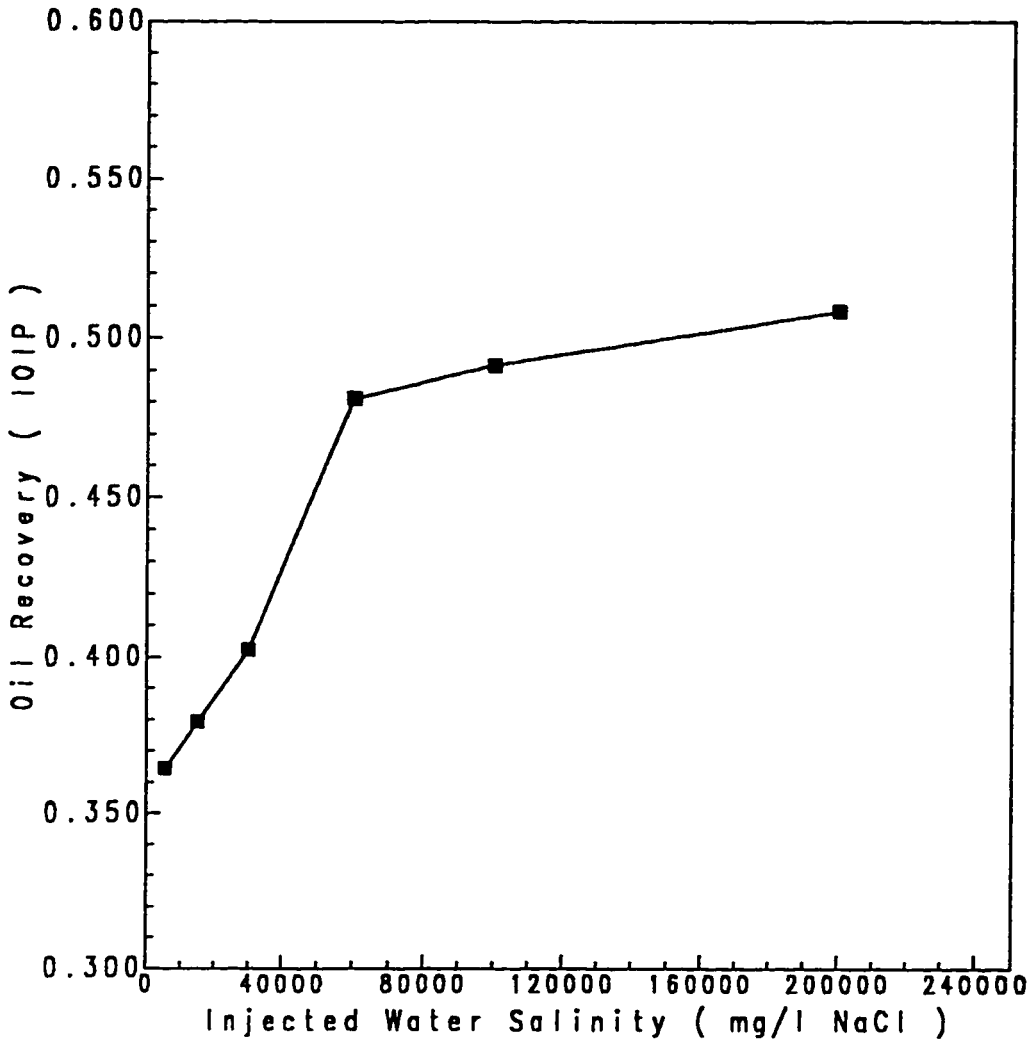


Fig. 4.2 – Breakthrough Recovery as a Function of Water Salinity

## Table 4.4

## Oil Recoveries After Injecting 5.0 P.V. for NaCl Brine Runs

| Run # | NaCl Concentration (mg/l) | IFT (dyne/cm) | $\frac{\mu_o}{\mu_w}$ | Oil Recovery (% IOIP) | Increase from Run#1 (% IOIP) | Difference Between Successive Runs (% IOIP) |
|---|---|---|---|---|---|---|
| 1 | 5,500 | 16.0 | 5.58 | 39.38 | -- | -- |
| 2 | 15,000 | 14.5 | 5.41 | 47.28 | 3.40 | 3.40 |
| 3 | 30,000 | 13.8 | 5.20 | 48.79 | 9.41 | 1.51 |
| 4 | 60,000 | 11.5 | 4.79 | 54.58 | 15.20 | 5.79 |
| 5 | 100,000 | 6.5 | 4.34 | 58.46 | 19.08 | 3.88 |
| 6 | 200,000 | 10.8 | 3.41 | 59.74 | 20.36 | 1.28 |

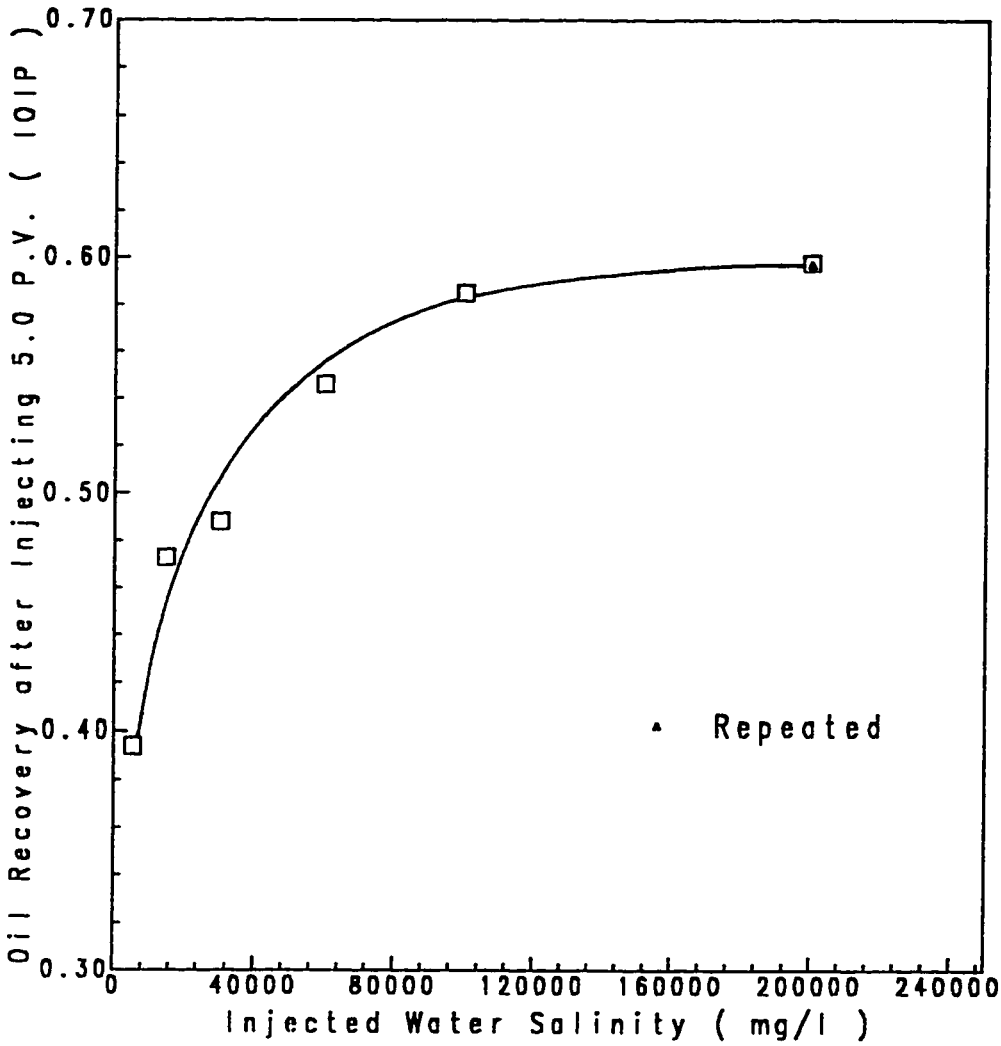


Fig. 4.3 – Oil Recovery vs. Injected Water Salinity for NaCl Brine Runs

cumulative water injected for these runs is shown in Fig. 4.4 and the analysis is given in Table 4.5. It is noticed that both breakthrough recovery and recovery at the end of the run increased with increasing injected water salinity. However, the increase was small compared to the increase among the same salinities in the NaCl brine runs.

Table 4.6 compares the recoveries from the three runs after injecting 5.0 P.V. The difference in oil recovery between the runs was not significant. For example, the difference between Run # 7 (sea water) and Run # 9 (100,000 mg/l Arab-D) is very small (2.46% IOIP). All the runs exhibited little oil recovery after breakthrough.

### 4.1.3 Discussion

The fractional flow equation [19] that describes the linear flow of oil and water in porous medium can be used to explain the results obtained in Section 4.1.1.

$$f_w = \frac{1 + \frac{k_o A}{\mu_o q_t}\left(\frac{dPc}{dx}\right)}{1 + \frac{k_{ro}}{k_{rw}}\frac{\mu_w}{\mu_o}}$$

Where:

$f_w$ = Fractional flow of water

A = Cross sectional area

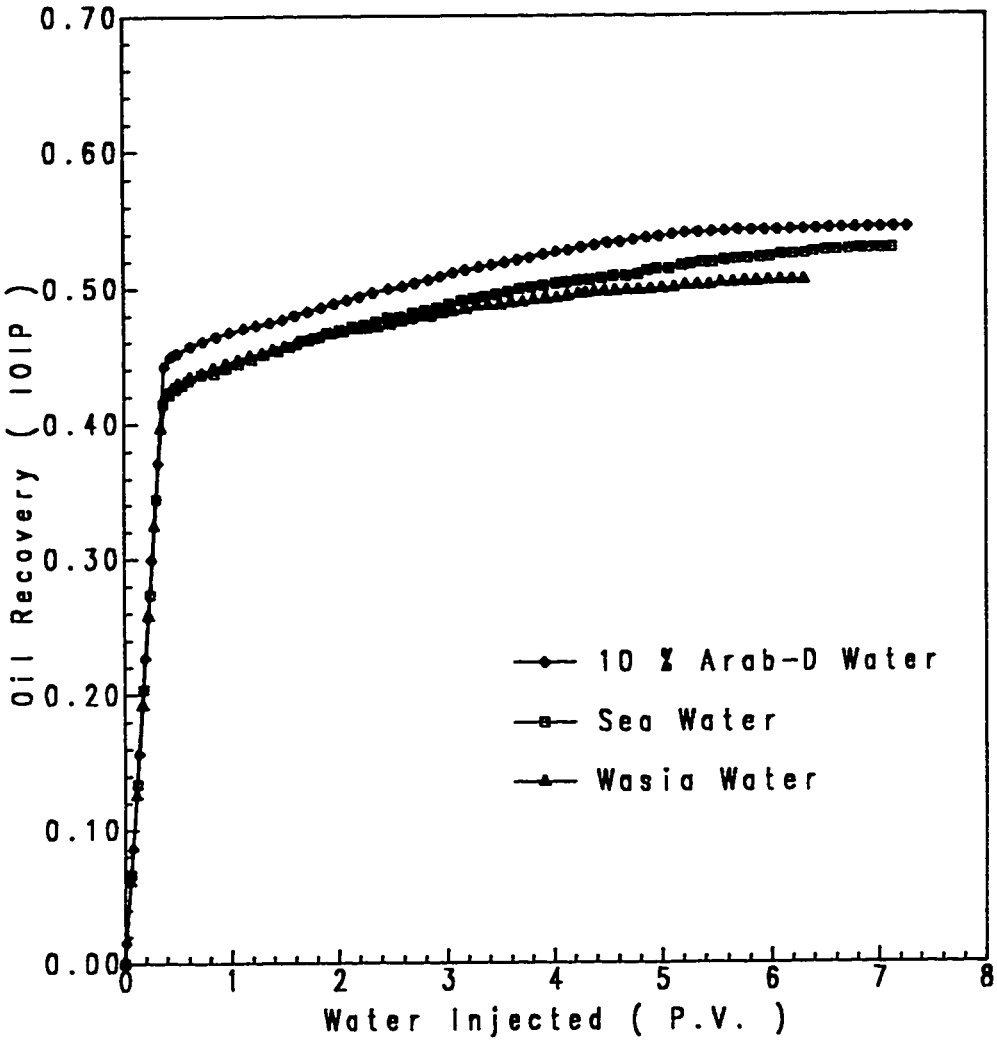


Fig. 4.4 - Oil Recovery vs. Water Injected for Actual Water Runs

## Table 4.5

## Breakthrough and End of Run Recoveries for Actual Water Runs

| Run # | Injected Water | IFT (dyne/cm) | $\frac{\mu_o}{\mu_w}$ | B.T.Recovery (% IOIP) | Recovery at the end of the Run (% IOIP) | Difference between B.T. and End of Run Recoveries (% IOIP) |
|---|---|---|---|---|---|---|
| 7 | Sea (55,624 mg/l) | 9.35 | 4.82 | 41.49 | 52.84 | 11.35 |
| 8 | Wasia ( 6,053 (mg/l) | 10.92 | 5.49 | 42.15 | 50.44 | 8.29 |
| 9 | Arab-D (100,000 mg/l) | 11.91 | 4.28 | 44.19 | 54.40 | 10.21 |

## Table 4.6

## Oil Recoveries After Injecting 5.0 P.V. for Actual Water Runs

| Run # | Injected Water | IFT (dyne/cm) | $\frac{\mu o}{\mu w}$ | Oil Recovery (% IOIP) | Increase from Run # 8 (% IOIP) | Difference Between Runs (% IOIP) |
|---|---|---|---|---|---|---|
| 8 | Wasia | 9.35 | 4.82 | 49.83 | -- | -- |
| 7 | Sea | 10.92 | 5.49 | 51.33 | 1.50 | 1.50 |
| 9 | 10% Arab-D | 11.91 | 4.28 | 53.79 | 3.96 | 2.46 |

$\mu_o$ = Oil viscosity

$\mu_w$ = Water viscosity

$k_{ro}$ = Oil relative permeability

$k_{rw}$ = Water relative permeability

$q_t$ = Total flow rate

$\frac{dPc}{dx}$ = Capillary pressure gradient.

Examination of the above equation indicates that oil displacement is affected by : water injection rate, viscosity ratio and implicitly by wettability and IFT.

The water injection rate was kept constant through all the runs, so it did not have any effect on oil recovery in this study.

Wettability is believed to have negligible effects on oil recovery in this study, since only Berea sandstone (considered to be a water-wet rock) and different brines (no additives that would alter the wettability) were used. The negligible effects of wettability are supported by the fact that in all the runs, a large fraction of the original oil in place was produced before breakthrough with little oil recovered afterwards as shown in Tables 4.2 and 4.5. This is a characteristic of water-wet rocks. The procedure used to clean the cores apparently did not alter the wettability of the rock samples. This was supported by repeated run (Run # R-6). When Run # 6 (200,000

mg/l NaCl) was repeated with cleaned cores, no significant change in oil recovery was observed as shown in Fig. 4.5.

Changing the salinity of the injected water has an influence on both IFT and water viscosity as was shown in Table 4.1, Fig. 3.3 and Fig.3.6. The water viscosity increases with increasing water salinity, while the oil viscosity was kept constant by using the same oil in all the runs. As a result, the viscosity ratio $(\frac{\mu_o}{\mu_w})$ decreases with increasing water salinity.

The increase in oil recovery (both breakthrough and at the end of the run) is believed to be caused by the reduction in IFT and the reduction in viscosity ratio.

Reducing IFT increases the tendency of water to displace oil by decreasing the capillary forces. Although the change in IFT among the runs was small (from 16.5 to 6.5 dyne/cm), it is believed to have an effect on oil recovery. This was observed by Mungan [20] , who showed an increase in oil recovery as IFT decreased from 40.0 to 0.5 dyne/cm as shown in Fig. 4.6.

Viscosity ratio is the other factor that contributed to the increase in oil recovery. The increase of viscosity ratio decreases the mobility of oil relative to the mobility of water, which causes an earlier breakthrough and hence, less oil recovery. In this study, the

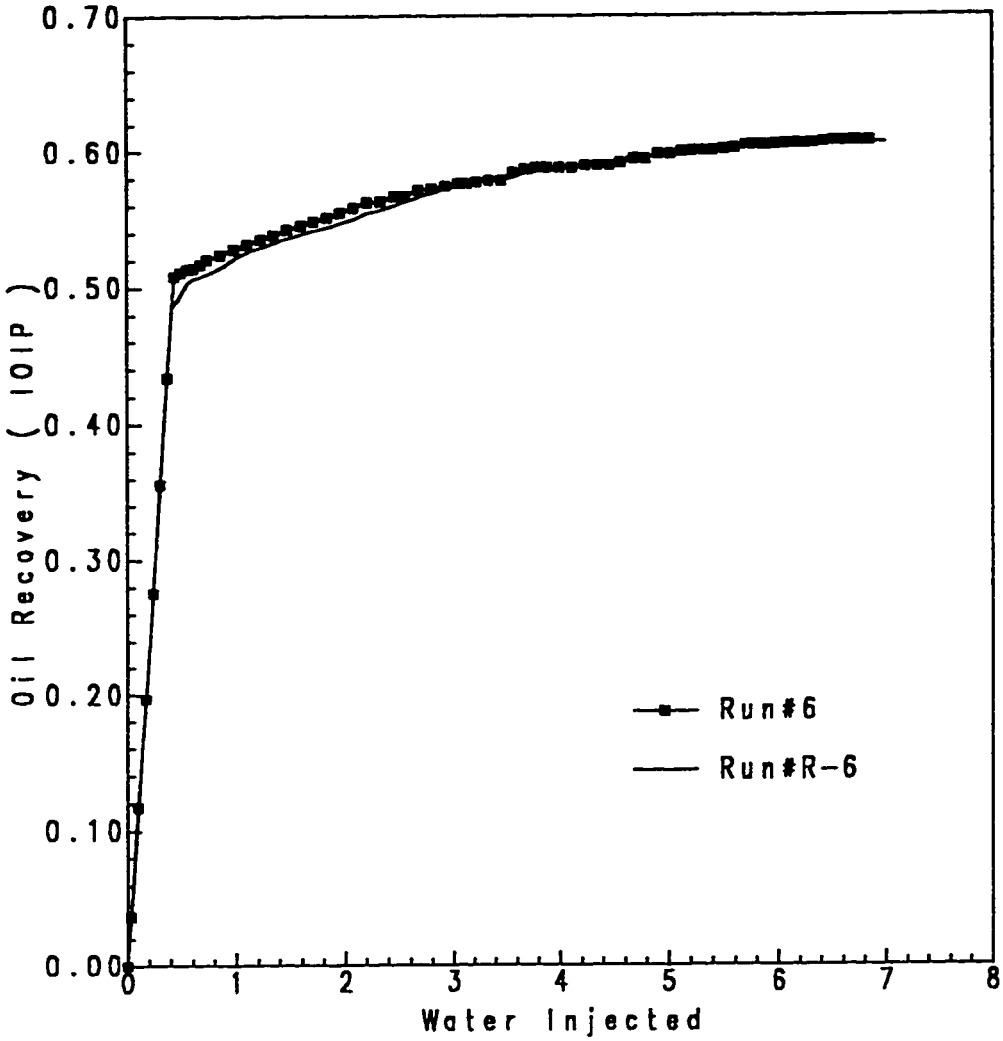


Fig. 4.5 - Rebeatability of Run#6

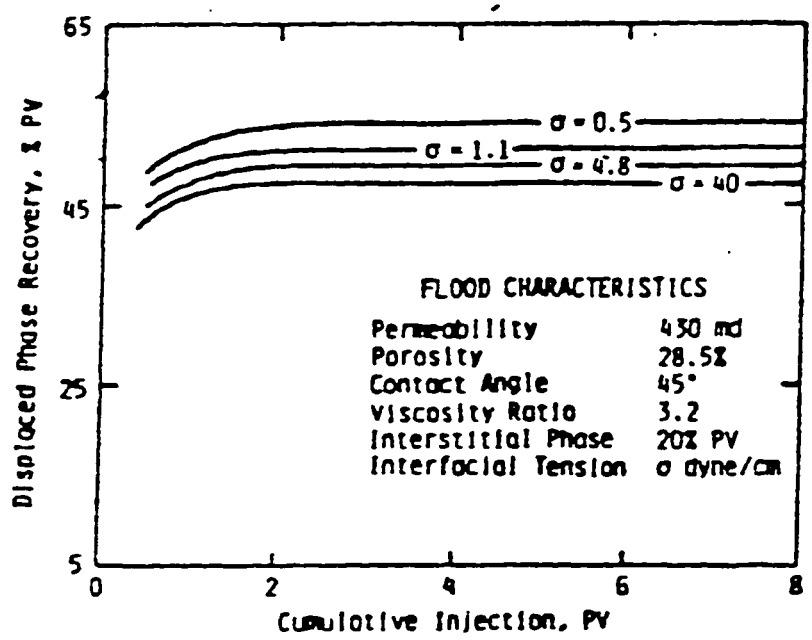


Fig. 4.6 : Effect of IFT on Displacement of a Nonwetting by a Wetting Liquid by Mungan (20).

viscosity ratio varied from 5.58 to 3.41.

The combined effects of IFT (capillary forces) and viscosity ratio (viscous forces) on oil recovery can be demonstrated by the capillary number ($N_{ca}$) which was introduced by Melrose and Brandner [21].

$$N_{ca} = \frac{V \mu_w}{\sigma_{ow}}$$

Where:

$N_{ca}$ = Capillary number

V = Interstitial velocity (cm/sec)

$\mu_w$ = Water viscosity (Pa.s)

$\sigma_{ow}$ = IFT between oil and water (dyne/cm).

As indicated before, the rate was kept constant, so it did not have any effect on oil recovery. As the capillary number increases, $S_{or}$ decreases. This can be achieved by either lowering IFT or increasing $\mu_w$. Fig. 4.7 shows $S_{or}$ as a function of the capillary number. It is observed that $S_{or}$ decreased with increasing capillary number.

### 4.1.4 NaCl Brine Runs vs. Actual Water Runs

Oil recovery from actual water runs is different from their

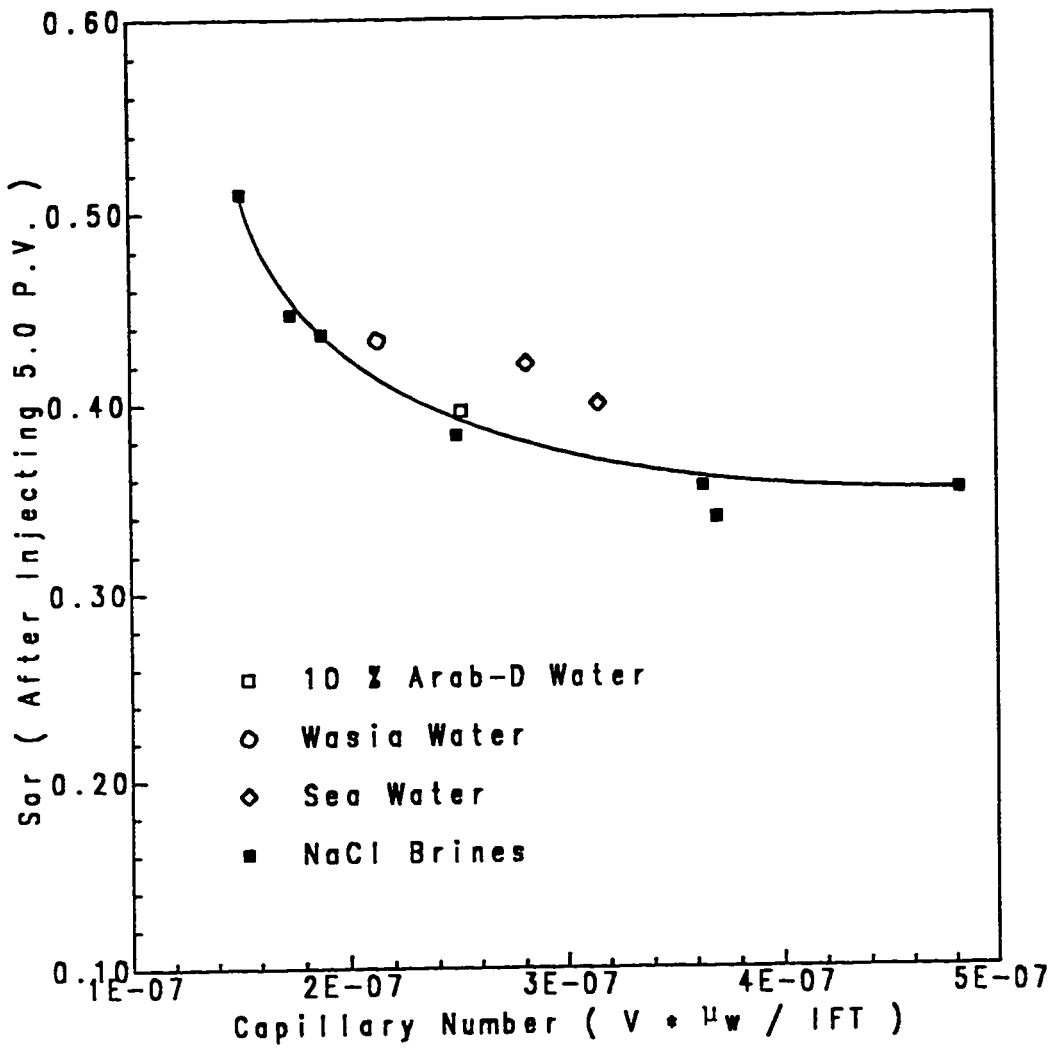


Fig. 4.7 – Sor vs. Capillary Number for All The Runs

salinity counterparts in NaCl brine runs. Fig. 4.8 shows $S_{or}$ vs water salinity for all the runs.

Run # 8 (Wasia water = 6053 mg/l, IFT = 10.92 dyne/cm) has 10.45% IOIP more recovery than Run # 1 (5500 mg/l NaCl, IFT = 16.0 dyne/cm). Run # 7 (sea water = 55623 mg/l, IFT = 9.35 dyne/cm) has almost the same recovery as Run # 4 (60000 mg/l NaCl, IFT = 11.5 dyne/cm). Run # 5 (100,000 mg/l NaCl, IFT = 6.5 dyne/cm) has 5.95% IOIP more recovery than Run # 9 (100,000 mg/l Arab-D, IFT = 11.9 dyne/cm).

From the above results, and Table 4.1, it can be seen that the difference in oil recovery could be attributed mainly to the variation in IFT.

The reduction in IFT between oil and water depends on the pH of the water and the concentration and type of salts dissolved. An example of the effect of pH on IFT is the reduction of IFT between 5500 mg/l NaCl brine and Wasia water (6053 mg/l). The higher pH value of Wasia water (7.85 compared to 6.9 for 5500 mg/l NaCl) reduced the IFT from 16.0 to 10.92 dyne/cm by making the water reacts with some constituents in the crude oil. Another example is the small reduction of IFT between sea water (55,623 mg/l) and 60,000 mg/l NaCl brine. The relatively high pH value in both Wasia and sea water is caused by the presence of bicarbonate ion ($HCO_3^-$) which is one of the chief sources of

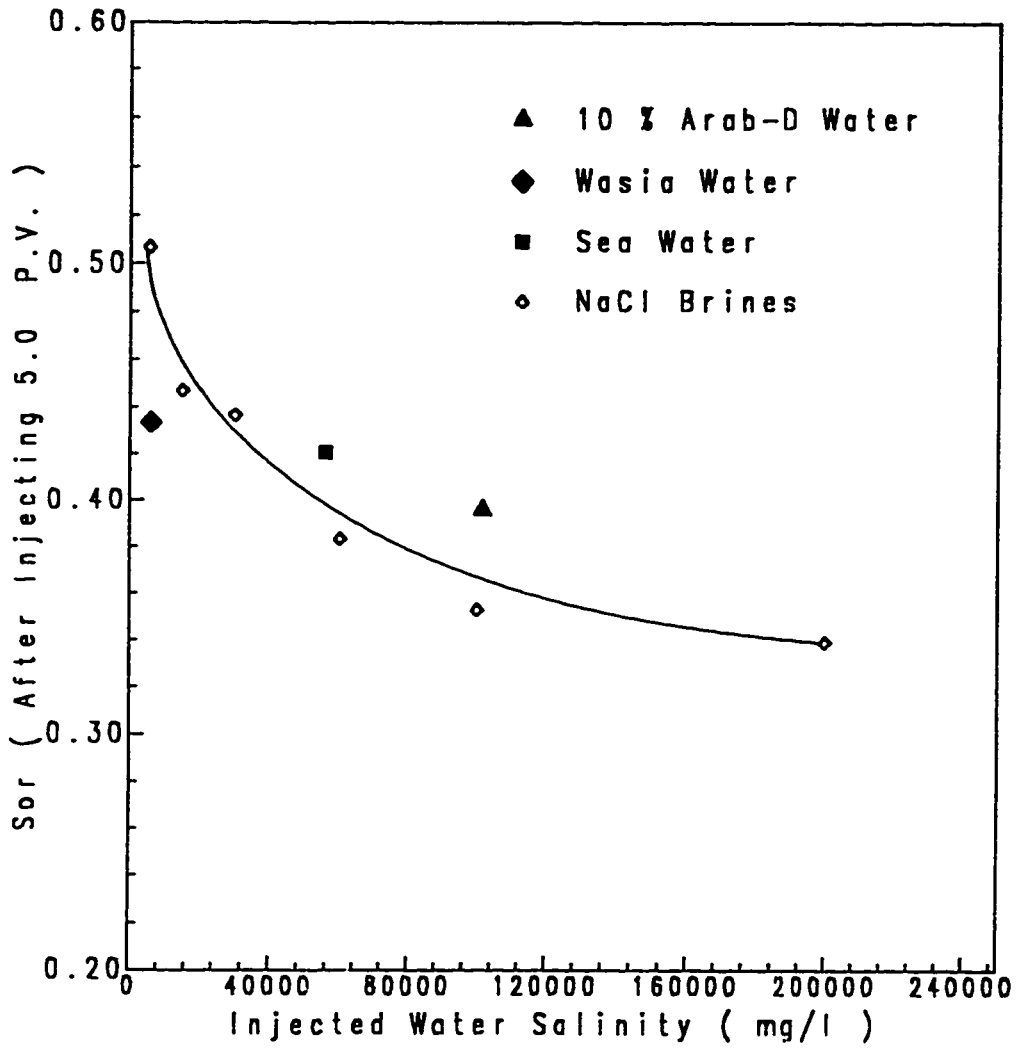


Fig. 4.8 – Sor vs. Injected Water Salinity for All The Runs

alkalinity in natural waters [22]. The presence of high concentrations of $Ca^{++}$ and $Mg^{++}$ in 100,000 mg/l Arab-D water is believed to be the cause of the higher IFT value (11.91 dyne/cm) compared to 100,000 mg/l NaCl brine (6.5 dyne/cm).

When 100,000 mg/l Arab-D water was prepared without $Ca^{++}$, IFT decreased from 11.91 to 10.83 dyne/cm. Without $Mg^{++}$, IFT decreased from 11.91 to 11.7 dyne/cm. Without both $Ca^{++}$ and $Mg^{++}$, IFT decreased to 9.66 dyne/cm. The effect of $Ca^{++}$, was greater than that of $Mg^{++}$, because the concentration of $Ca^{++}$, was higher. To keep the salinity constant, $Na^{+}$ was added to compensate for the absent ions.

### 4.1.5 Effect of Salinity on Absolute Permeability

Although the Berea core samples were fired at 900°C for 18 hours, to stabilize the clay content, the absolute permeability of one core sample was measured using different salinity brines. Fig. 4.9 shows how the absolute permeability varied with water salinity. The permeability increased from 580.5 md at 5500 mg/l NaCl to 600.6 md at 100,000 mg/l NaCl and, finally to 628.7 md at 260,000 mg/l NaCl. This small variation is believed to be caused by little swelling of the clay particles in the core. This small variation in permeability does not have any effect on oil recovery.

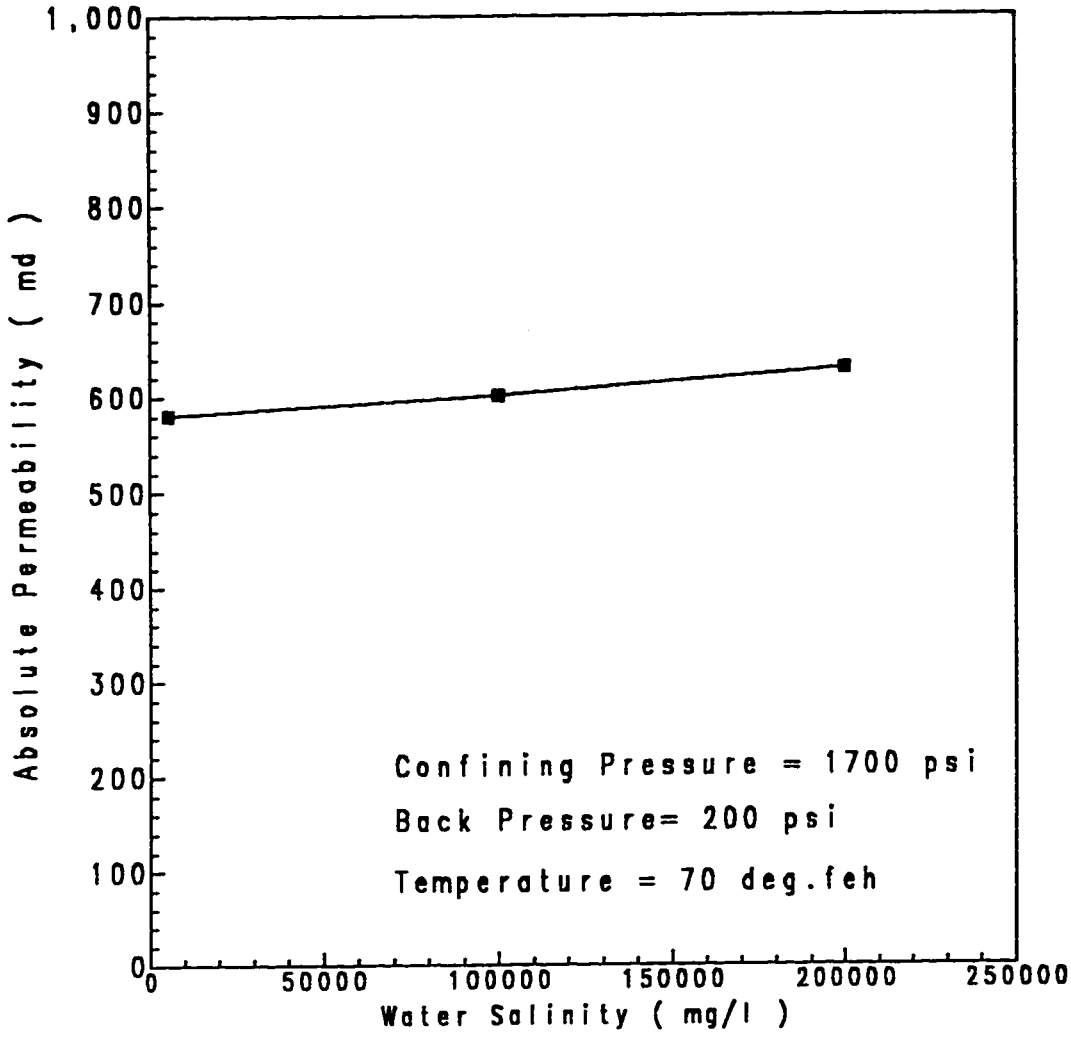


Fig. 4.9 - Effect of Salinity on Absolute Permeability

## 4.2 CAPILLARY PRESSURE MEASUREMENTS

Capillary pressure measurements are essential for the analysis of water flooding experiments. A plot of capillary pressure vs. saturation of a rock sample can be used to determine the irreducible water saturation and residual oil saturation of the rock sample.

In this study, the Hassler and Brunner method [23] was used to determine the capillary pressure curves from centrifuge data.

The experiments were conducted on Berea cores (L = 1 inch, D = 1 inch) obtained from the same block, using oil and different brines. All the experiments were conducted at 90°C. The core samples were initially saturated with brines. The drainage capillary pressure curves were obtained by displacing the brines with oil. At the end of each drainage cycle, the imbition capillary pressure curve was obtained.

Table 4.7 presents the properties of the core samples and summary of the results.The effect of water salinity on drainage and imbition capillary pressure curves is shown in Figs. 4.10 and 4.11.

The following remarks can be observed from the drainage capillary pressure curves. First, the curves shifted slightly towards lower water saturations as the IFT decreased. Second, the residual wetting phase saturation decreased from 10.44% at 16.0 dyne/cm to 8.99% at 11.5 dyne/cm, and finally to 8.38% at 9.35 dyne/cm.

## Table 4.7

### Summary of Capillary Pressure Experiments

| Core # | K (md) | L (cm) | Porosity ( % ) | Pore Vol. (cc) | Brine Used | IFT (dyne/cm) | $S_{wi}$ at the end of Drainage Cycle (% P.V.) | $S_{or}$ at the end of Imbibition Cycle (% P.V.) | $S_{or}$ at the end of Flooding Experiment (% P.V.) |
|---|---|---|---|---|---|---|---|---|---|
| 1 | 735.6 | 2.60 | 24.45 | 3.12 | 5,500(mg/l) NaCl | 16.0 | 10.44 | 43.42 | 50.7 |
| 2 | 757.3 | 2.39 | 24.09 | 2.85 | 60,000(mg/l) NaCl | 11.5 | 8.99 | 28.60 | 38.31 |
| 3 | 740.2 | 2.66 | 24.56 | 3.208 | 100,000(mg/l) NaCl | 6.5 | ** | 15.68 | 34.88 |
| 4 | 732.6 | 2.58 | 24.56 | 3.112 | 200,000(mg/l) NaCl | 10.8 | ** | 24.69 | 32.88 |
| 5 | 737.6 | 2.44 | 24.14 | 2.89 | 55624(mg/l) Sea Water | 9.35 | 8.38 | ** | ** |

** The core sample was broken during the run

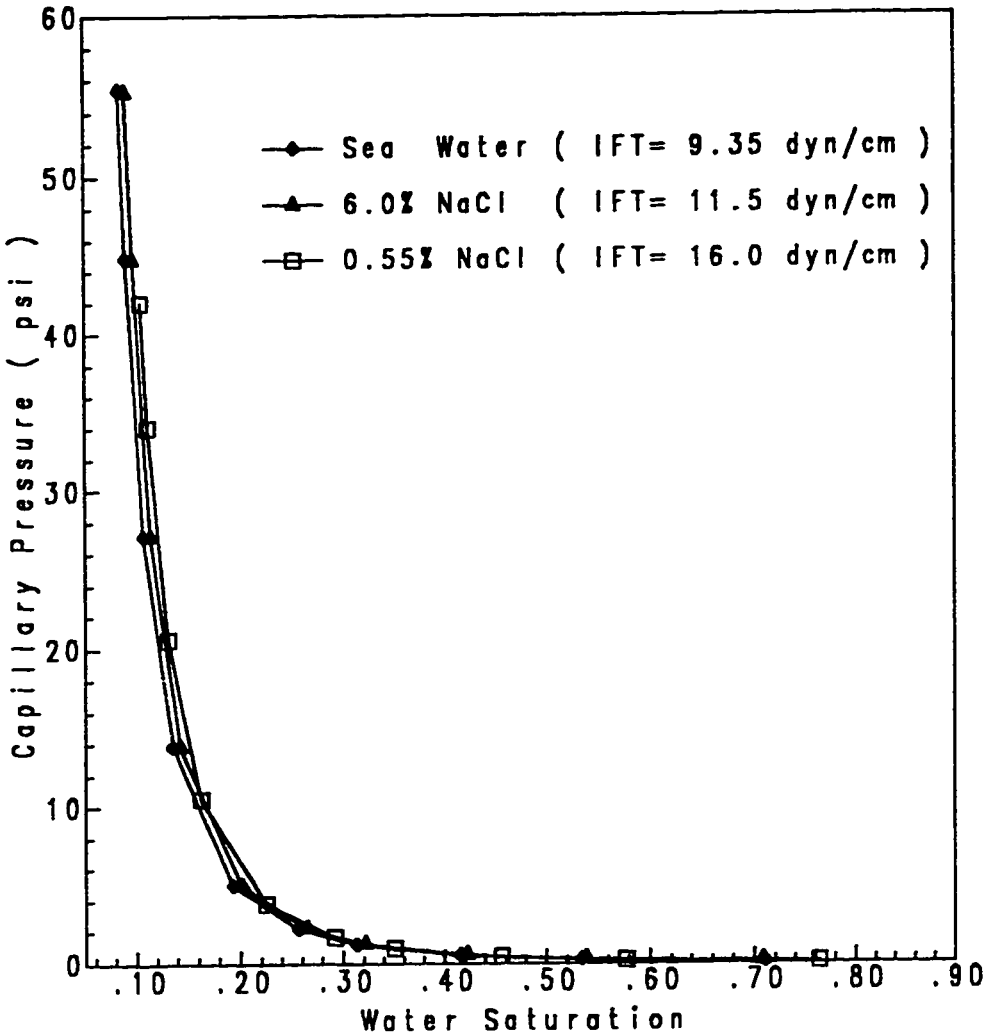


Fig. 4.10 - Drainage Capillary Pressure Curves

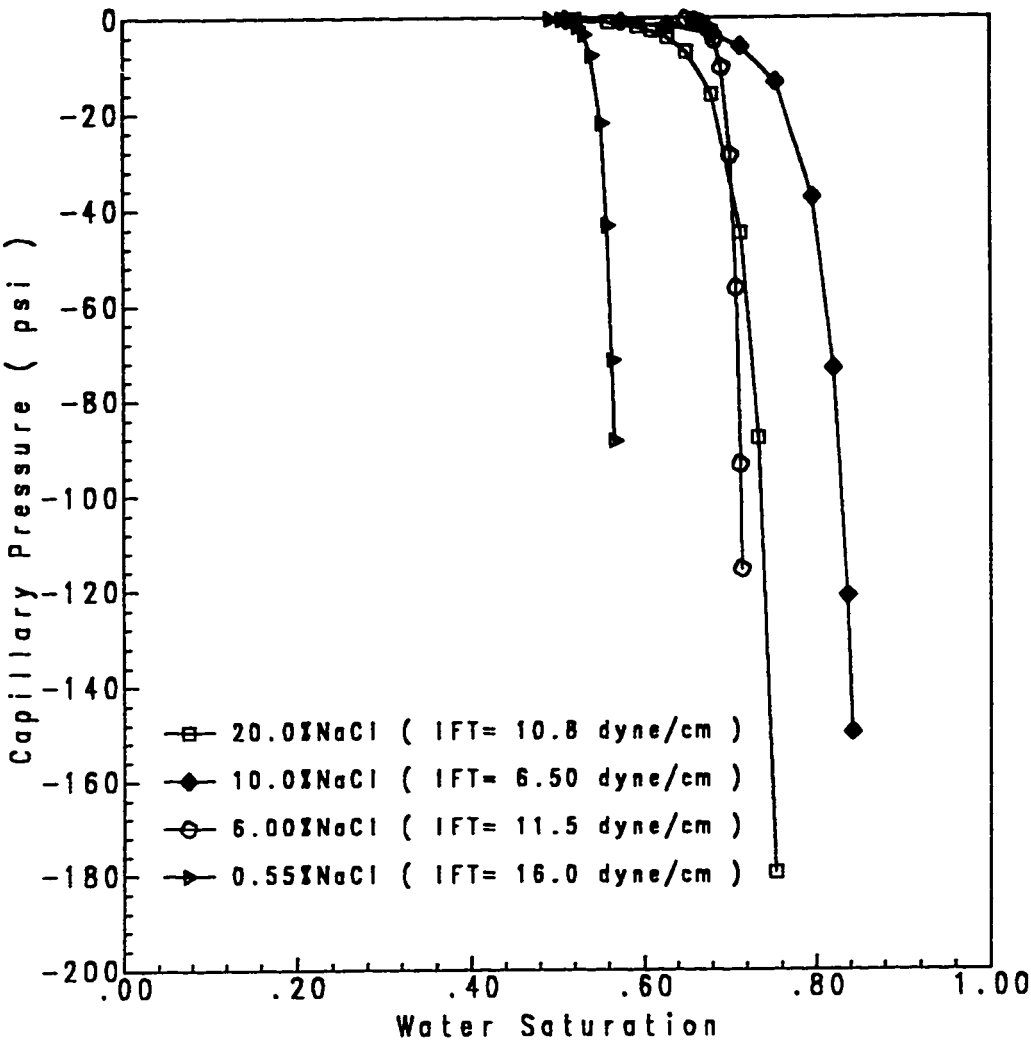


Fig. 4.11 – Imbibition Capillary Pressure Curves

However, the imbition curves showed a significant shift towards higher water saturation (lower oil saturation) with decreasing IFT. $S_{or}$ decreased from 43.4% at 16.0 dyne/cm, to 28.6% at 11.5 dyne/cm, to 24.7% at 10.8 dyne/cm, and finally to 15.7% at 6.5 dyne/cm.

The residual oil saturations observed at the end of the imbition cycles were lower than those obtained in the flooding experiments as shown in Table 4.7. The differences are probably caused by the differences in flow behavior. Whereas the capillary number $(\frac{\mu_w V}{\sigma_{ow}})$ controls $S_{or}$ obtained by flooding experiments, the bond number $(\frac{\Delta \rho g K}{\phi \sigma_{ow}})$ significantly affects the fluid distribution in the capillary pressure experiments [24].

## 4.3 RELATIVE PERMEABILITIES

Oil recovery as a function of cumulative water injected for all the runs was shown in Fig. 4.1 and Fig. 4.4. It is noticed that a little oil is produced after breakthrough, which means small change in water saturation is obtained after breakthrough. Pressure drop as a function of cumulative water injected for NaCl brine runs and actual water runs are shown in Figs. 4.12 and 4.13 respecatively. All the curves exhibited a pressure rise until breakthrough and then the pressure

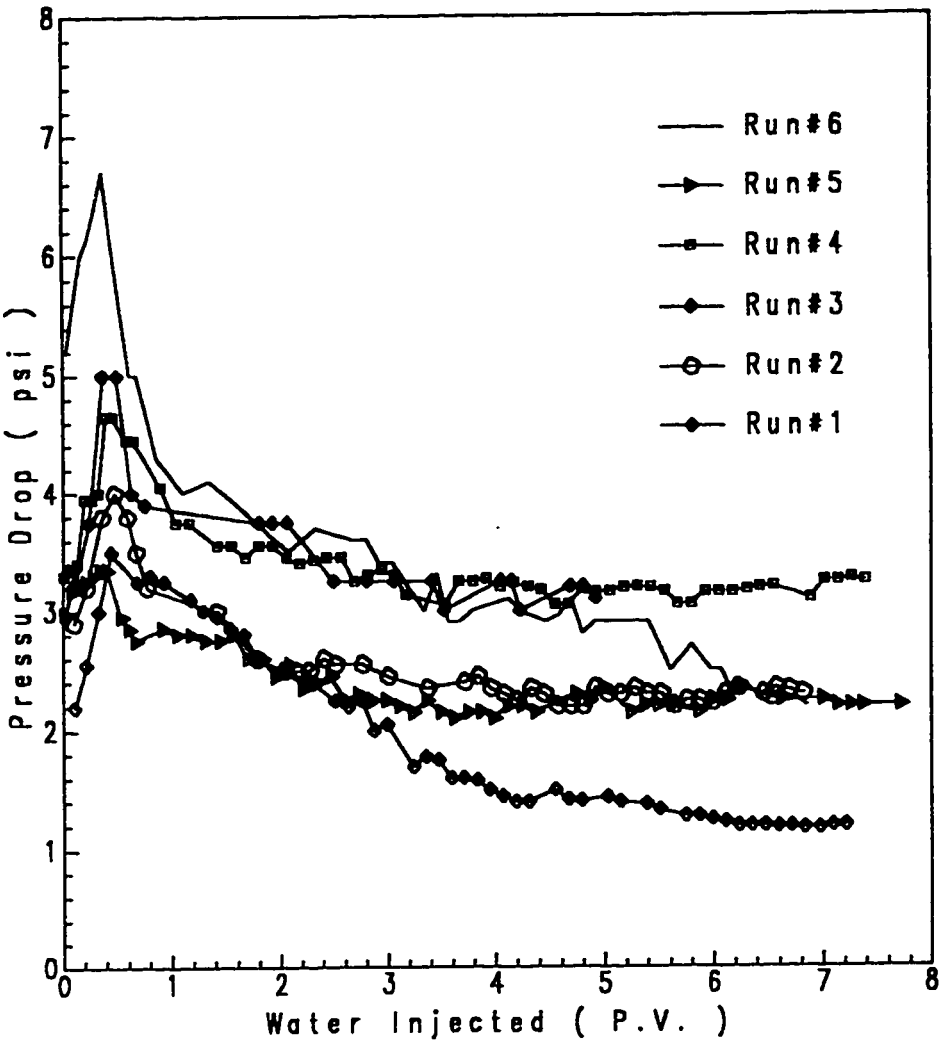


Fig. 4.12 - Pressure Drop vs. Water Injected for NaCl Brine Runs

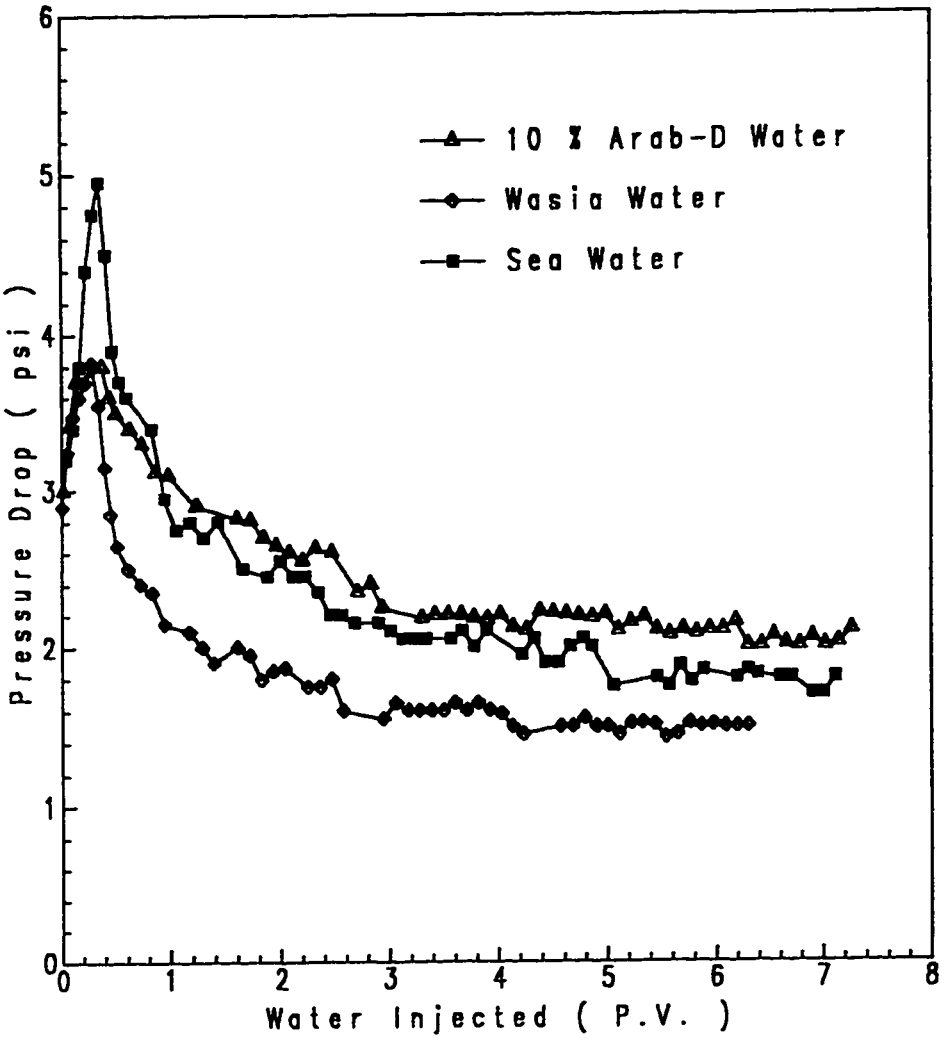


Fig. 4.13 - Pressure Drop vs. Water Injected for Actual Water Runs

drops, before it stabilizes when no more oil is produced.

Unsteady-state relative permeability curves were determined using Johnson-Bossler-Naumann method [25]. Table 4.8 shows some data related to the calculation of relative permeabilities. The effective permeability to oil at irreducible water saturation was used as a reference permeability. The relative permeability curves for NaCl brine runs are shown in Figs. 4.14 and 4.15. The curves for actual water runs are shown in Figs. 4.16 and 4.17. It is noticed that the irreducible water saturation was almost constant for all the runs (15%), while $S_{or}$ changed with the injected brine.

For NaCl brine runs, both oil and water relative permeabilities shifted to higher water saturations with increasing water salinity. For actual water runs, oil relative permeabilities are close to each other, while water relative permeabilities are different. However, the differences are small compared to NaCl brine runs.

Relative permeability ratio $\left(\frac{k_{ro}}{k_{rw}}\right)$ curves as a function of water saturation are used to compare how $k_{ro}$ changed compared to $k_{rw}$. Fig. 4.18 shows relative permeability ratio curves for NaCl brine runs. It is noticed that as the salinity increased, the relative permeability ratio increased at the same water saturation. Although the curves of Run # 5 (100,000 mg/l) and Run # 6 (200,000 mg/l) are almost the same, the

**Table 4.8**

**Summary of Data Related to Relative Permeability Calculation**

| Run # | Swi (% P.V.) | $k_{eo}$ at $S_{wi}$ (md) | Sor at the end of the run (P.V.) | $k_{ew}$ at Sor (md) |
|---|---|---|---|---|
| 1 | 15.91 | 460.63 | 0.507 | 97.44 |
| 2 | 15.23 | 459.73 | 0.4368 | 111.02 |
| 3 | 14.49 | 492.8 | 0.4161 | 234.05 |
| 4 | 15.59 | 456.4 | 0.3831 | 89.57 |
| 5 | 15.32 | 411.36 | 0.3487 | 158.20 |
| 6 | 15.72 | 485.28 | 0.3288 | 111.36 |
| 7 | 13.75 | 670.1 | 0.3953 | 197.66 |
| 8 | 13.57 | 631.33 | 0.4280 | 190.63 |
| 9 | 14.51 | 600.95 | 0.3956 | 175.87 |

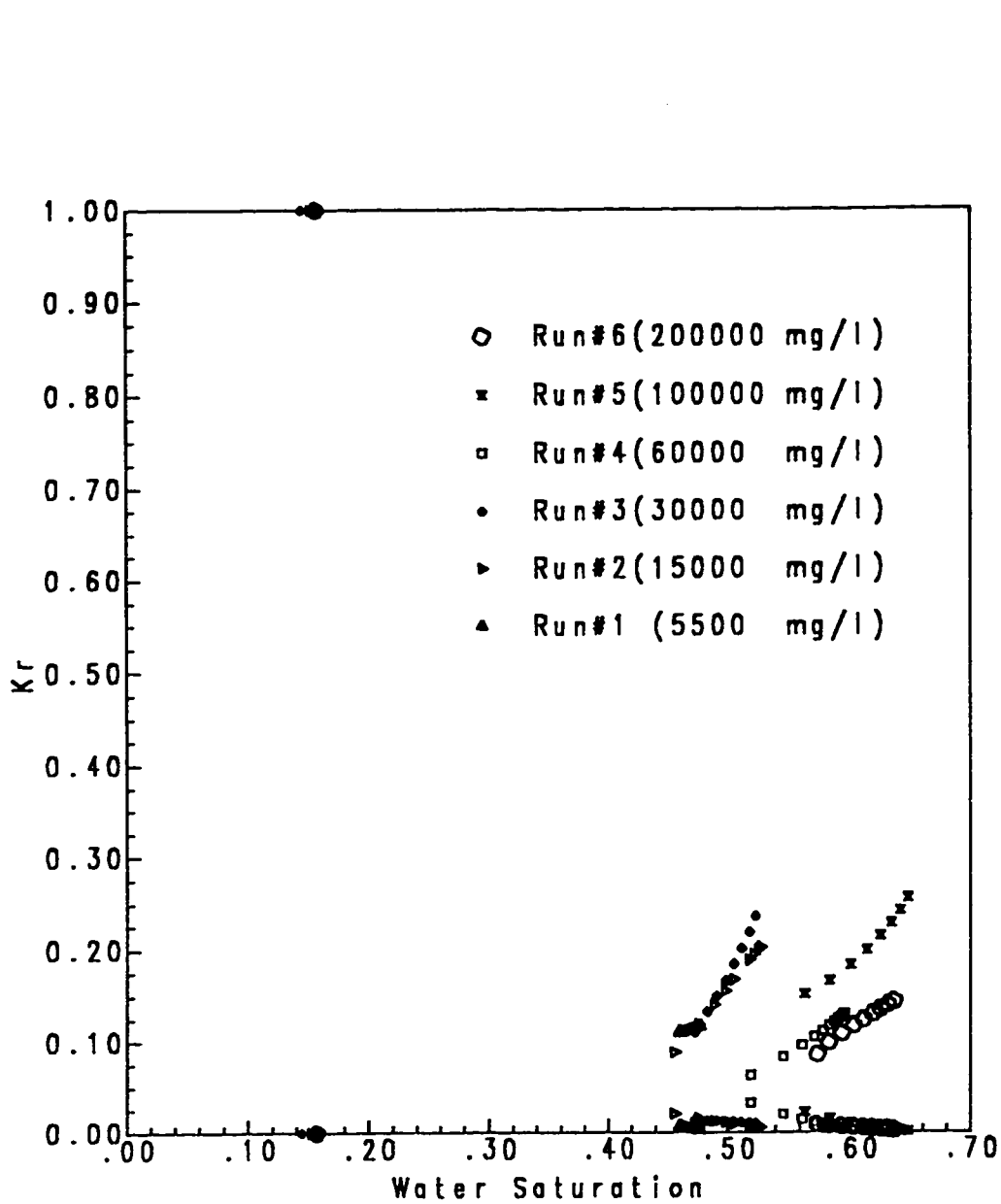


Fig. 4.14 – Relative Permeability Curves for NaCl Brine Runs

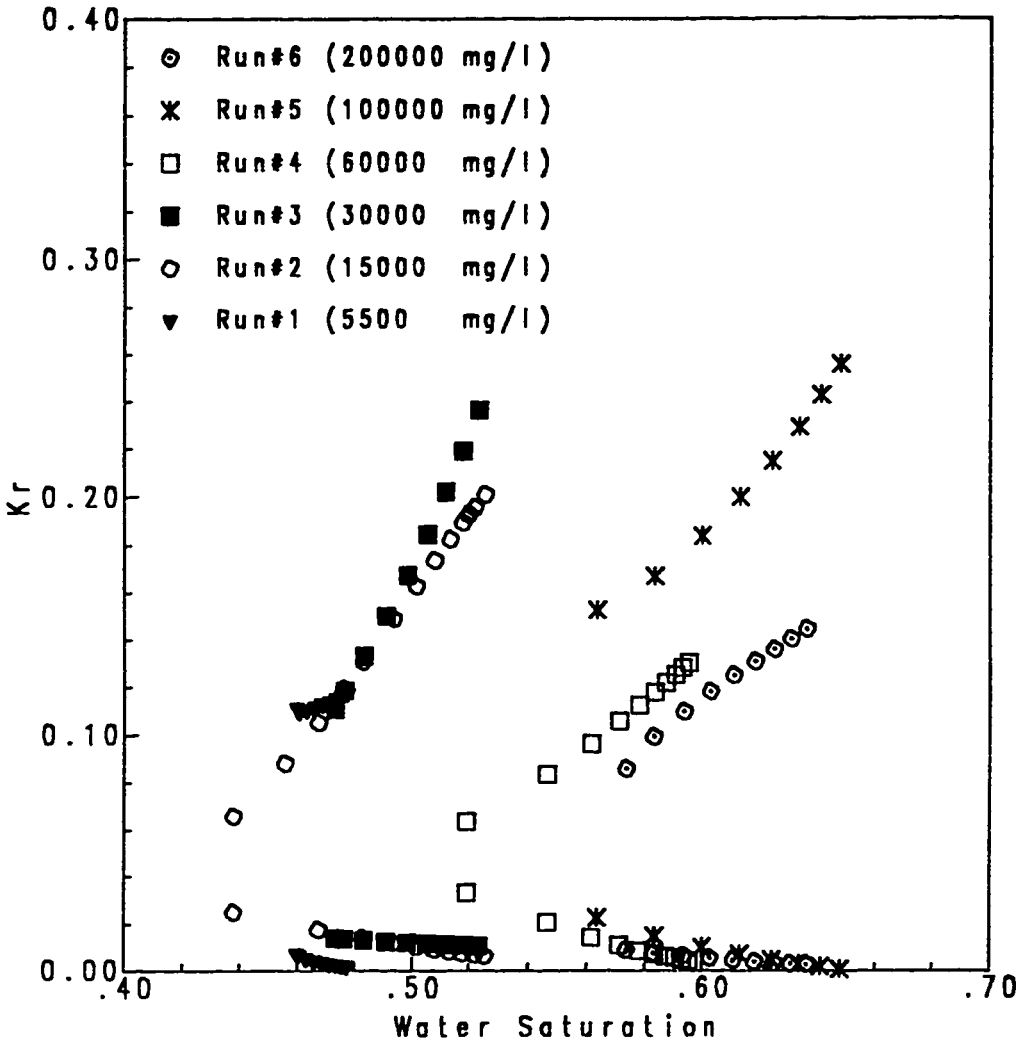


Fig. 4.15 – Relative Permeability Curves for NaCl Brine Runs

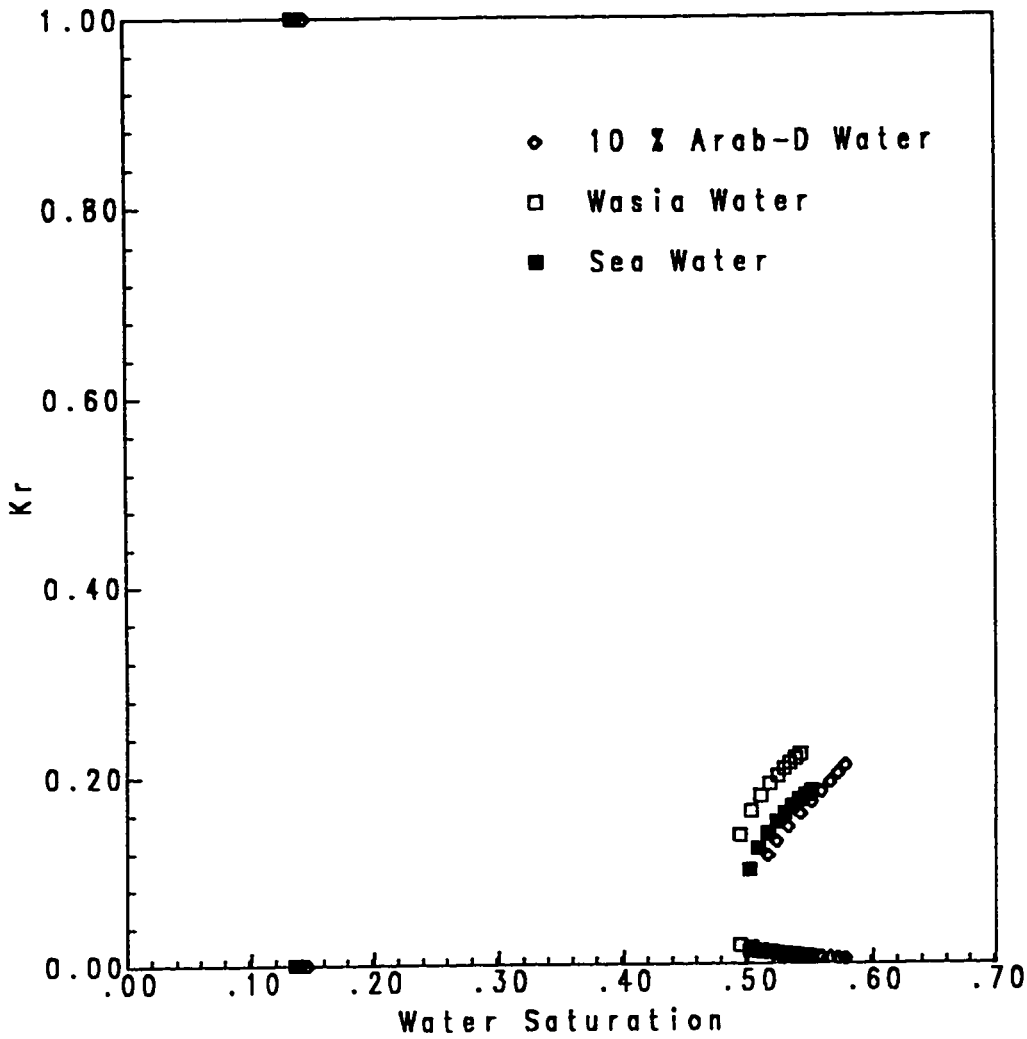


Fig. 4.16 - Relative Permeability Curves for Actual Water Runs

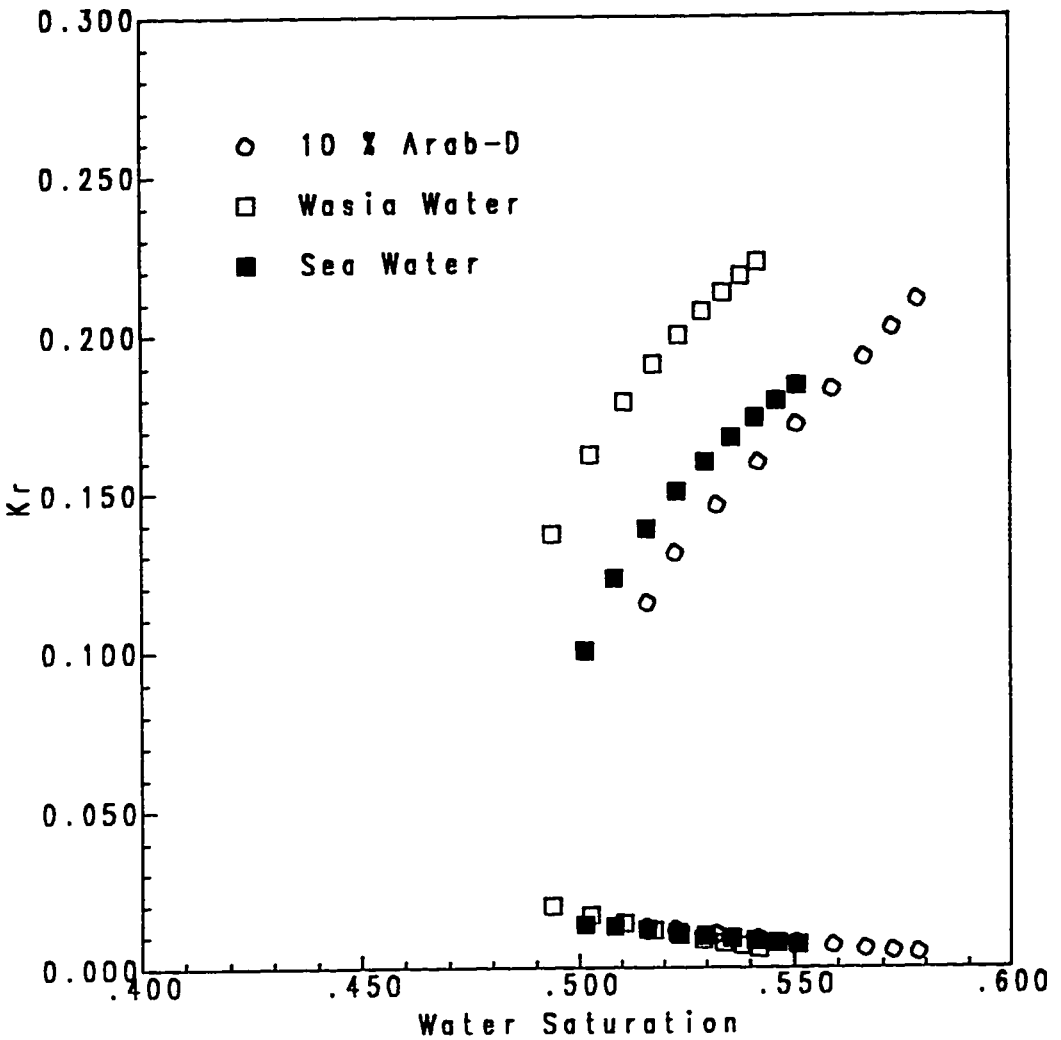


Fig. 4.17 – Relative Permeability Curves for Actual Water Runs

shift towards higher water saturations is believed to be caused by the reduction in IFT from 16.0 to 6.50 dyne/cm.

Fig. 4.19 shows relative permeability ratio curves for actual water runs. It is noticed that as the injected water salinity increased, the relative permeability ratio increased at the same water saturation, similar to the NaCl brine runs. The difference among relative permeability ratio curves for actual water runs is small compared to the difference between NaCl brine runs. This is expected as the IFT varied from 9.35 to only 11.91 dyne/cm.

The dependence of relative permeabilities on IFT has been shown in the literature to be controversial. Some investigators [24,16] found that relative permeabilities to oil and water were affected only when the IFT values were lower than 0.1 dyne/cm. However, some investigators found similar results as found in this study. Leverette [27] showed that reduction of IFT from 35 to 5 dyne/cm increased the permeabilities of both oil and water phases by 20 to 30%. Mungan [20] found that the relative permeability ratios (wetting/non-wetting) decreased with decreasing IFT from 25 to 5 dyne/cm.

## 4.4 PRODUCED WATER SALINITY

The produced water salinity for NaCl brines runs as a function of cumulative water injected is shown in Fig. 4.20. It is observed that the salinity of the produced water is close to the connate water salinity

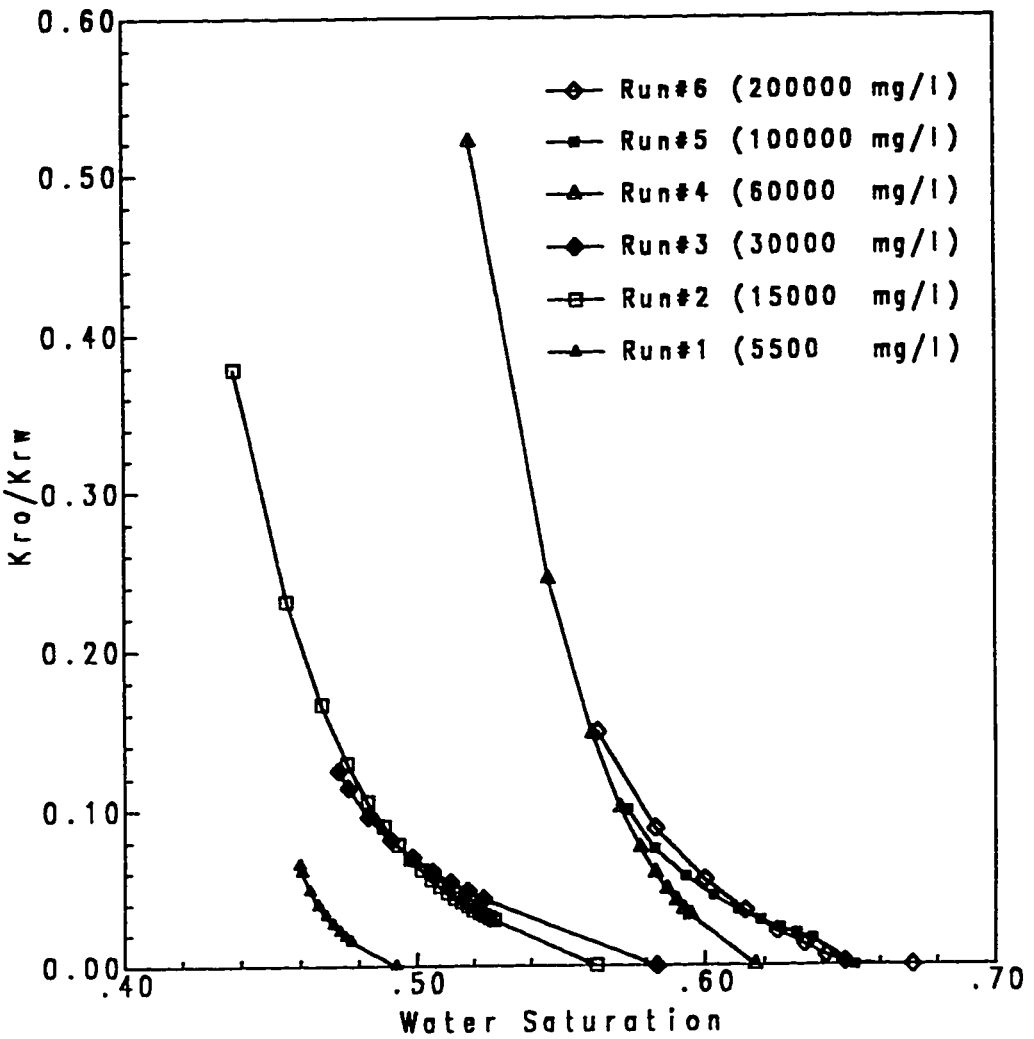


Fig. 4.18 - Relative Permeability Ratio Curves for NaCl Brine Runs

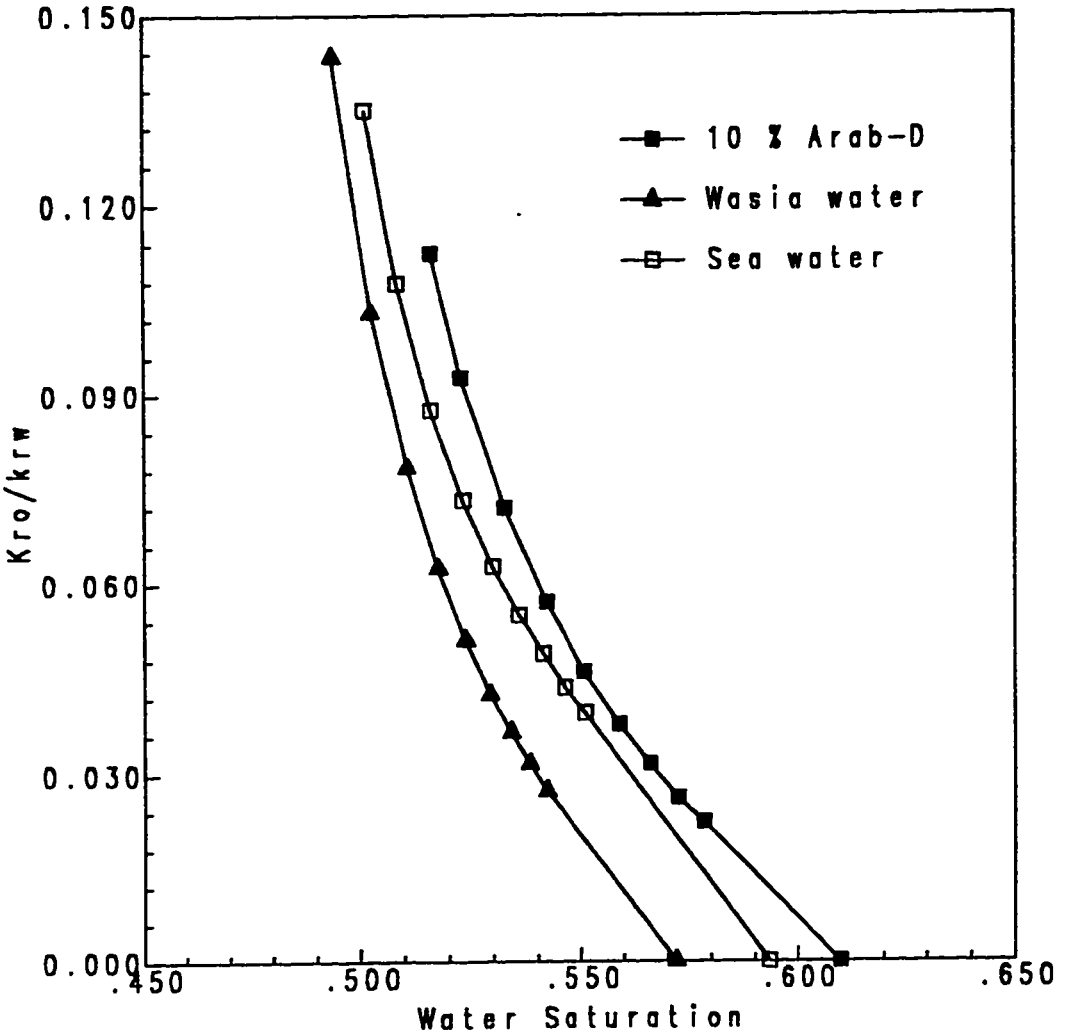


Fig. 4.19 – Relative Permeability Ratio Curves for Actual Water Runs

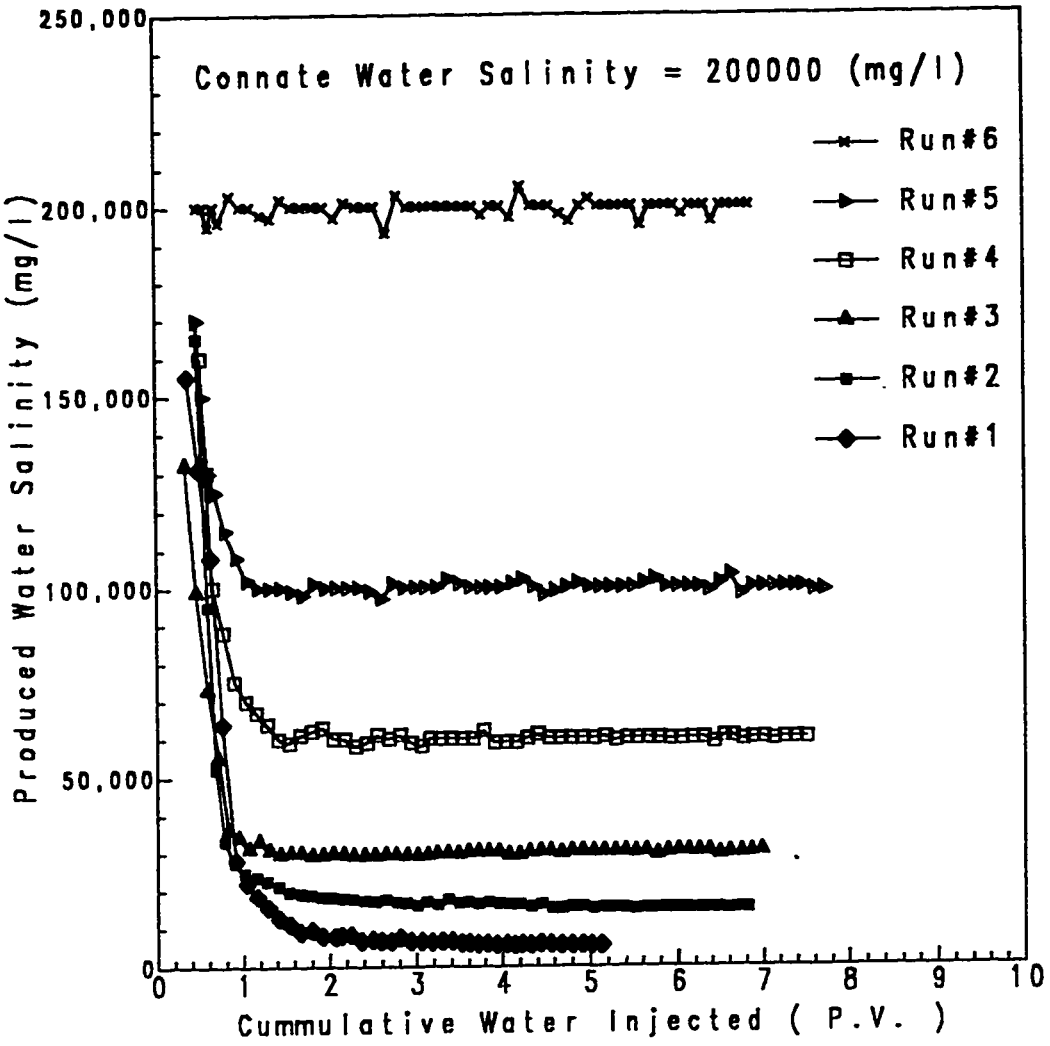


Fig. 4.20 – Produced Water Salinity vs. Water Injected for NaCl Brine Runs

(200,000 mg/l) at breakthrough. The salinity then decreases sharply until it reaches the injected water salinity after injecting about 1.5 P.V. This is an indication that all the connate water is produced after injection of 1.5 P.V. and the mixing between the injected water and connate water lasted for approximately 45 minutes (the time required for injection of 1.5 P.V.).

## 4.5 COMPATIBILITY OF WATERS

One of the primary causes of scale formation and injection well plugging is the mixing of two or more waters which are incompatible. The waters may be quite stable at all system conditions and do not present any scale problems. However, once they are mixed, reaction between dissolved ions in the individual waters may form insoluble compounds. When this occurs, the waters are said to be incompatible.

The commonly precipitated compounds that are formed as a result of incompatibility of mixed waters are, calcium sulphate ($CaSO_4$), barium sulphate ($BaSO_4$), strontium sulphate ($SrSO_4$), and calcium carbonate ($CaCO_3$). Three important variables are related to scale formation. Temperature, in relation to the solubility of the possible scale former, pressure changes, and brine concentration [28].

Compatibility of water mixtures is assessed either by solubility calculations or by experimental testing. Experimental testing is far

more dependable if samples of the waters to be mixed are obtained [29].

In this study, three compatibility tests and three flooding experiments were performed to study the compatibility of connate Arab-D water with sea water (Run # 7), Wasia water (Run # 8) and finally 100,000 mg/l Arab-D water (Run # 9).

### 4.5.1 Compatibility Tests

For testing the compatibility of two waters, A (either sea, Wasia or 100,000 mg/l Arab-D) and B (connate Arab-D), the following procedure was used [22]. Samples of the waters were taken, filtered to remove any suspended solids, and heated at 90°C for several hours. Seven culture tubes were set in a rack and numbered one through seven. Waters A and B, were added to the tubes in the volumes shown in the table below.

| Tube # | 1 | 2 | 3 | 4 | 5 | 6 | 7 |
|---|---|---|---|---|---|---|---|
| Water A, ml | 50 | 45 | 35 | 25 | 15 | 5 | 0 |
| Water B, ml | 0 | 5 | 15 | 25 | 35 | 45 | 50 |

As a result of these tests, it was observed that no precipitation occurred when mixing either Wasia or 100,000 mg/l Arab-D waters with connate Arab-D water in all the tubes. However, when sea water was

mixed with connate Arab-D, precipitation occurred immediately in Tubes 2 to 5. The precipitate was clear after 5.0 minutes and tube 4 had the maximum precipitate. The tubes were left for 24 hours at 90°C. Then, the clear water (no precipitate) from the four tubes was taken by a syringe and sent for ICP analysis.

The original ions concentration of the mentioned tubes was calculated knowing the compositions of sea water and Arab-D water which are shown in Table 4.9, and the volumes proportions in each tube. It is noticed from this table that sea water has a high concentration of $SO_4^{--}$ (4180 mg/l) which indicates that sulphate salts are likely to precipitate. Tables 4.10 through 4.13 show the calculated ions concentration, and the ions concentration of the analyzed clear water for tubes 2 to 5 respectively. The difference between the two columns represents the composition of the precipitate. In all, the four tubes the precipitate was mainly calcium sulphate ($CaSO_4$) with some strontium sulphate ($SrSO_4$).

### 4.5.2 Flooding Experiments

When a water that is not compatible with formation water is injected into a reservoir, deposits form only where the waters make contact and mix. When reactions occur between the chemical constituents of incompatible waters to form insoluble products, not all the reacting ions are precipitated. Precipitation occurs only to adjust

## Table 4.9

### Mineral Constituents of Sea Water and Arab-D Water Used for the Compatibility Test

| ION | Sea Water | Arab-D Water |
|---|---|---|
| $Na^{+}$ | 17,260 | 53,050 |
| $Ca^{++}$ | 615 | 29,960 |
| $Mg^{++}$ | 2,035 | 4,390 |
| $Ba^{++}$ | 0 | 9.34 |
| $Sr^{++}$ | 9.5 | 1,200 |
| $HCO_3^{-}$ | 144.1 | 51.6 |
| $Cl^{-}$ | 31,380 | 148,100 |
| $SO_4^{--}$ | 4,180 | 142 |
| TDS (mg/l) | 55,623 | 236,903 |

## Table 4.10

### Sea Water and Arab-D Water Compatibility Test for Tube No. 2

**Arab-D Water : 6.0 ml**

**Sea Water : 44.0 ml**

| ION | Calculated Water Analysis (mg/l) | Clear Water Analysis (mg/l) | Difference (mg/l) |
|---|---|---|---|
| $Na^{+}$ | 21,555 | 21,460 | 95 |
| $Ca^{++}$ | 4,136 | 3,300 | 836 |
| $Mg^{++}$ | 2,318 | 2,390 | -- |
| $Ba^{++}$ | 1.0 | 1.0 | -- |
| $Sr^{++}$ | 152 | 126 | 26 |
| $HCO_3^{-}$ | 133 | -- | -- |
| $Cl^{-}$ | 44,803 | 44,820 | -- |
| $SO_4^{--}$ | 3,695 | 3,180 | 515 |

## Table 4.11

### Sea Water and Arab-D Water Compatibility Test for Tube No. 3

**Arab-D Water : 16.5 ml**

**Sea Water : 33.5 ml**

| ION | Calculated Water Analysis (mg/l) | Clear Water Analysis (mg/l) | Difference (mg/l) |
|---|---|---|---|
| $Na^{+}$ | 29,070 | 29,080 | -- |
| $Ca^{++}$ | 10,299 | 9,710 | 589 |
| $Mg^{++}$ | 2,812 | 2,880 | -- |
| $Ba^{++}$ | 3.0 | 1.0 | 2 |
| $Sr^{++}$ | 402 | 357 | 45 |
| $HCO_3^{-}$ | 114 | 158.4 | -- |
| $Cl^{-}$ | 69,898 | 70,730 | -- |
| $SO_4^{--}$ | 2,847 | 1,340 | 1,507 |

## Table 4.12

### Sea Water and Arab-D Water Compatibility Test for Tube No. 4

**Arab-D Water : 25.0 ml**

**Sea Water : 25.0 ml**

| ION | Calculated Water Analysis (mg/l) | Clear Water Analysis (mg/l) | Difference (mg/l) |
|---|---|---|---|
| $Na^{+}$ | 35,155 | 35,140 | 15 |
| $Ca^{++}$ | 15,288 | 14,830 | 458 |
| $Mg^{++}$ | 3,213 | 3,260 | -- |
| $Ba^{++}$ | 5 | 3 | 2 |
| $Sr^{++}$ | 605 | 596 | 9 |
| $HCO_3^-$ | 98 | 59 | 39 |
| $Cl^-$ | 87,406 | 87,120 | 286 |
| $SO_4^{--}$ | 2,161 | 1,080 | 1,081 |

## Table 4.13

### Sea Water and Arab-D Water Compatibility Test for Tube No. 5

**Arab-D Water : 34.5 ml**

**Sea Water : 15.5 ml**

| ION | Calculated Water Analysis (mg/l) | Clear Water Analysis (mg/l) | Difference (mg/l) |
|---|---|---|---|
| $Na^{+}$ | 41,955 | 41,950 | 5 |
| $Ca^{++}$ | 20,864 | 20,790 | 74 |
| $Mg^{++}$ | 3,660 | 3,730 | -- |
| $Ba^{++}$ | 6 | 5 | 1 |
| $Sr^{++}$ | 830 | 830 | -- |
| $HCO_3^{-}$ | 80.3 | 42.8 | 37.5 |
| $Cl^{-}$ | 113,084 | 114,510 | -- |
| $SO_4^{--}$ | 1,394 | 673 | 721 |

the product of the reacting ions concentrations to the thermodynamic solubility product or to provide a saturated solution [22].

As stated earlier, three flooding experiments were performed to study the compatibility of sea water, Wasia water, and 100,000 mg/l Arab-D water with connate Arab-D water. The analyses of these waters were shown in Table 3.3.

#### *4.5.2.1 Results*

When the flooding experiment was completed, the oil and water volumes were measured in each tube for recovery analysis. Then, several tubes that represent different pore volumes of injected water were selected for analysis. The produced water was taken from each tube by a syringe, placed in a clean glass vial, and sent for ICP analysis.

The produced waters were analyzed for the following ions :

$$Na^{+}, Ca^{++}, Mg^{++}, Ba^{++}, Sr^{++}, HCO_3^{-}, SO_4^{--}, \text{ and } Cl^{-}.$$

Appendix B shows the produced waters analysis for the three runs. For each ion, a plot of the ion concentration vs. cumulative water injected was made to observe how the concentration changes as the flood proceeds. The plots for Run # 7 are shown in Figs. 4.21 through 4.29, for Run # 8 in Figs. 4.30 through 4.38 and for Run # 9 in Figs. 4.39 through 4.47. The reference line in each plot

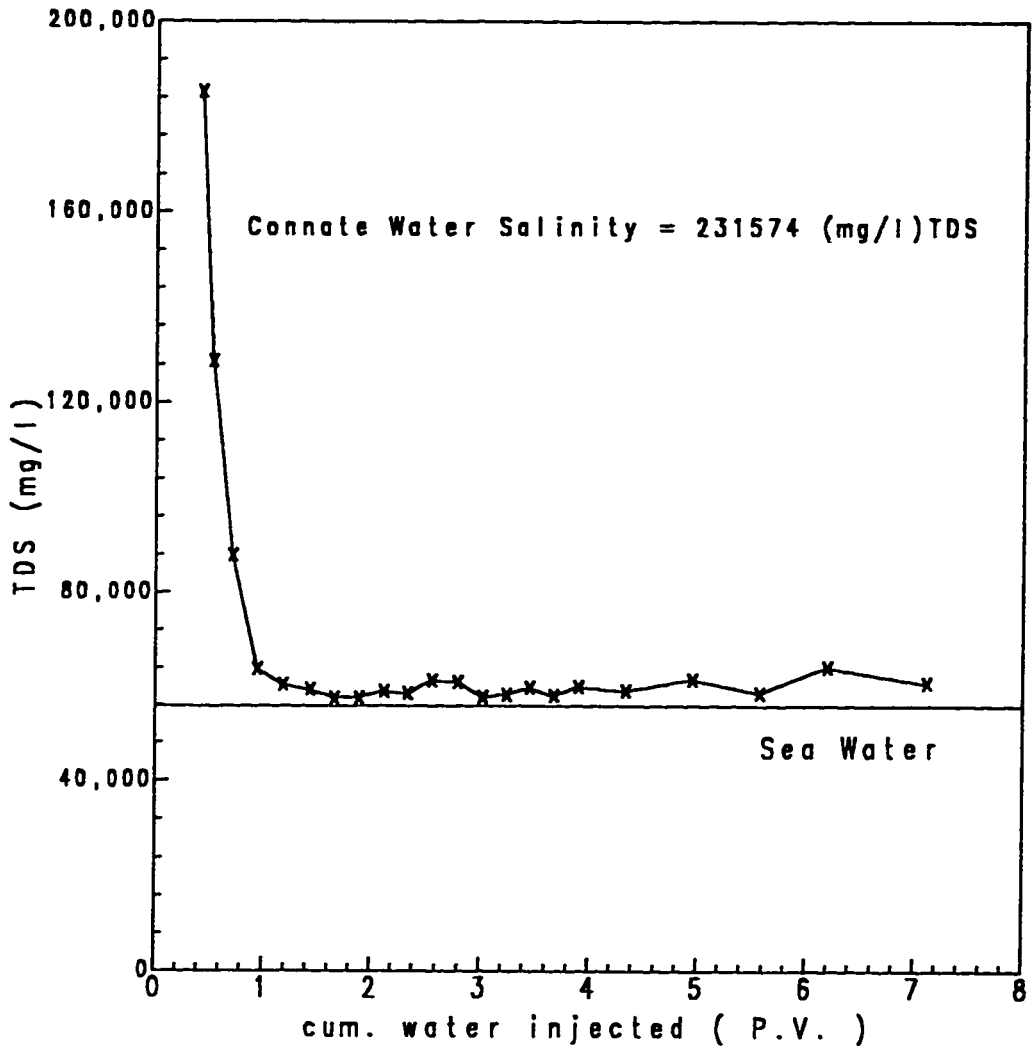


Fig. 4.21 - Total Dissolved Solids vs. Cum. Water Injected for Run#7

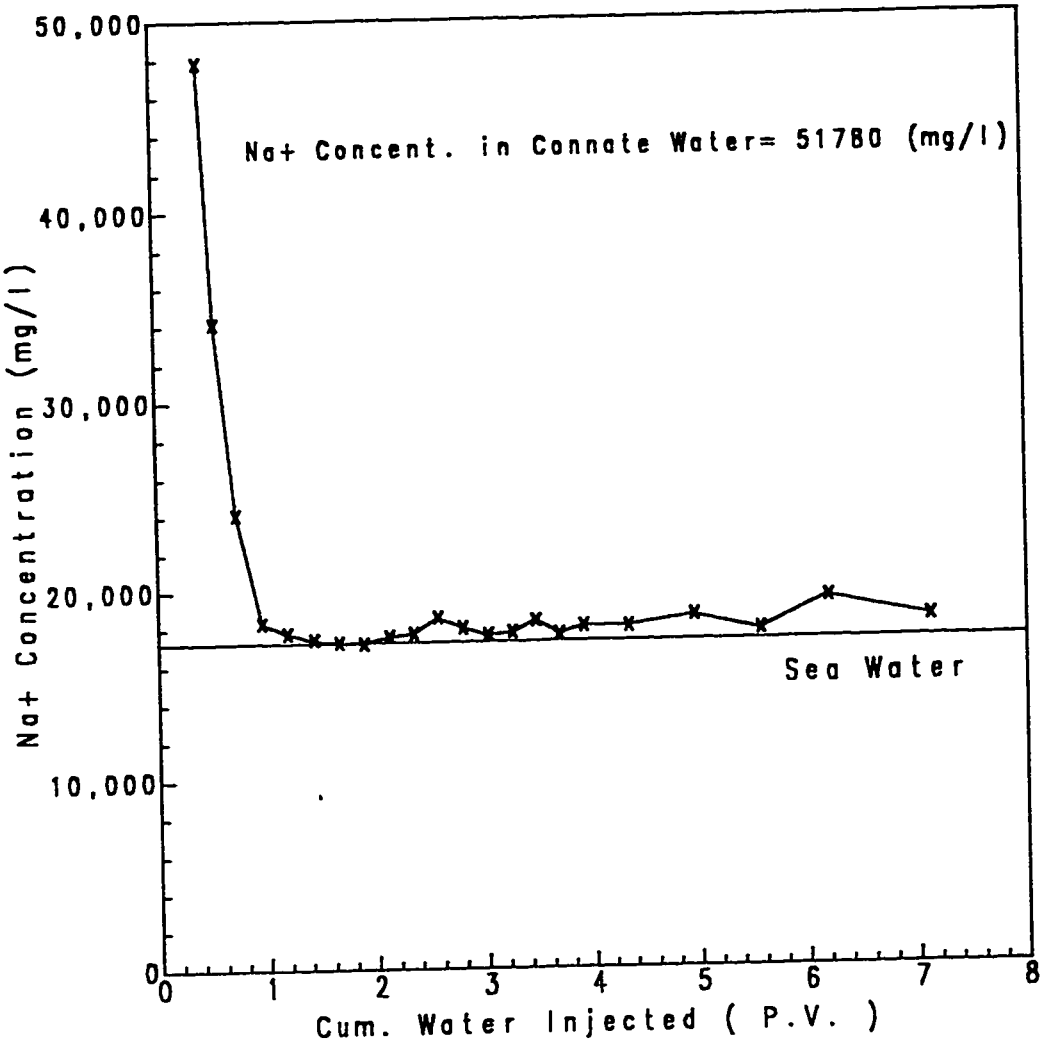


Fig. 4.22 – Na+ Concentration vs. Cum. Water Injected for Run#7

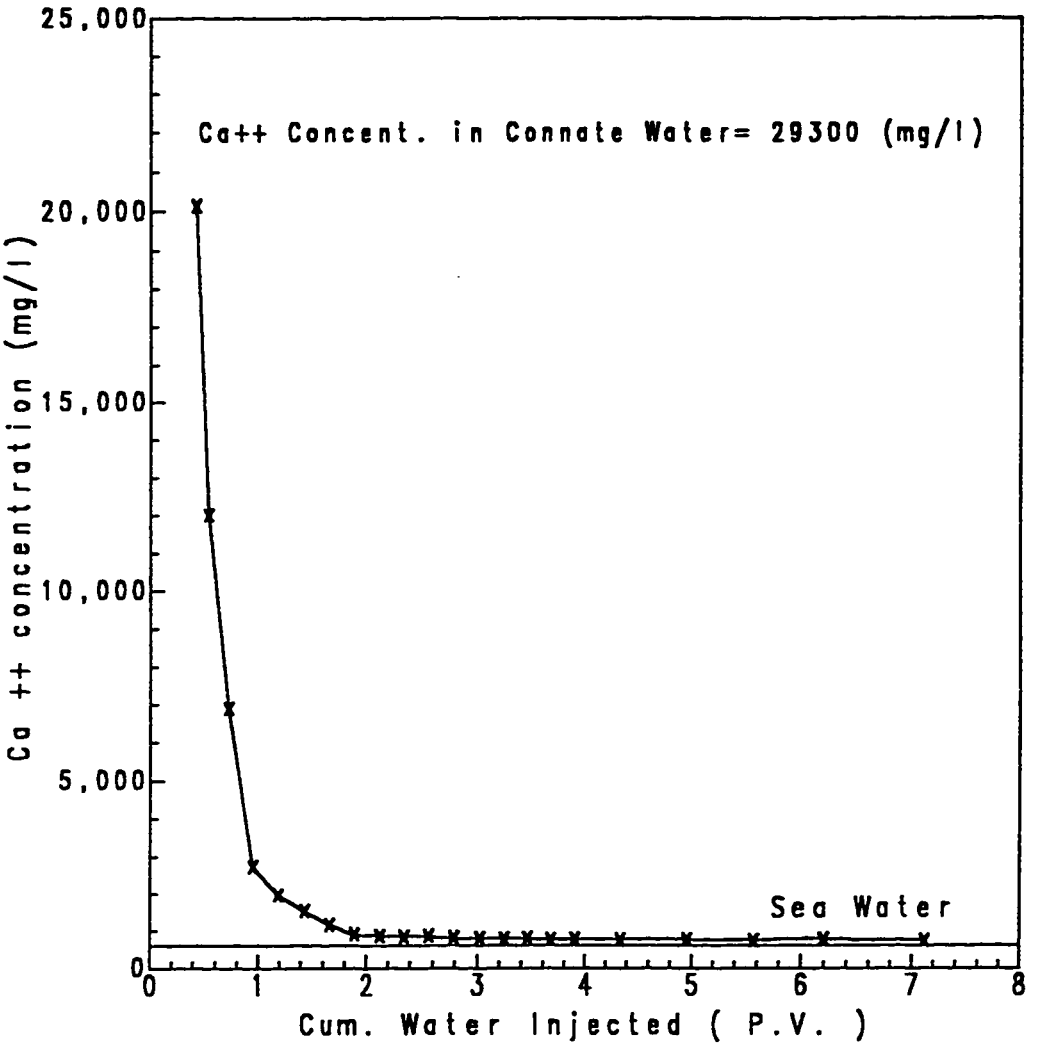


Fig. 4.23 - Ca++ Concentration vs. Cum. Water Injected for Run#7

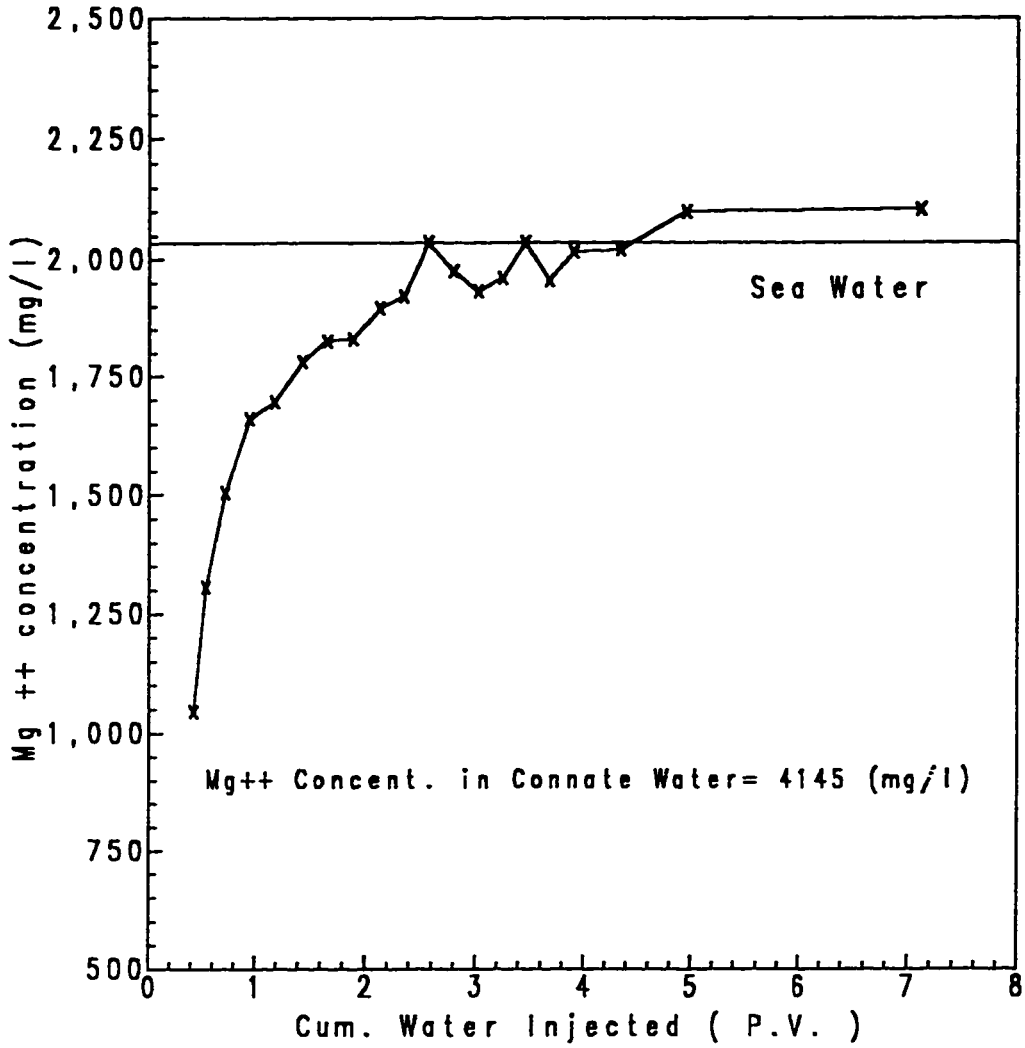


Fig. 4.24 – Mg++ Concentration vs. Cum. Water Injected for Run#7

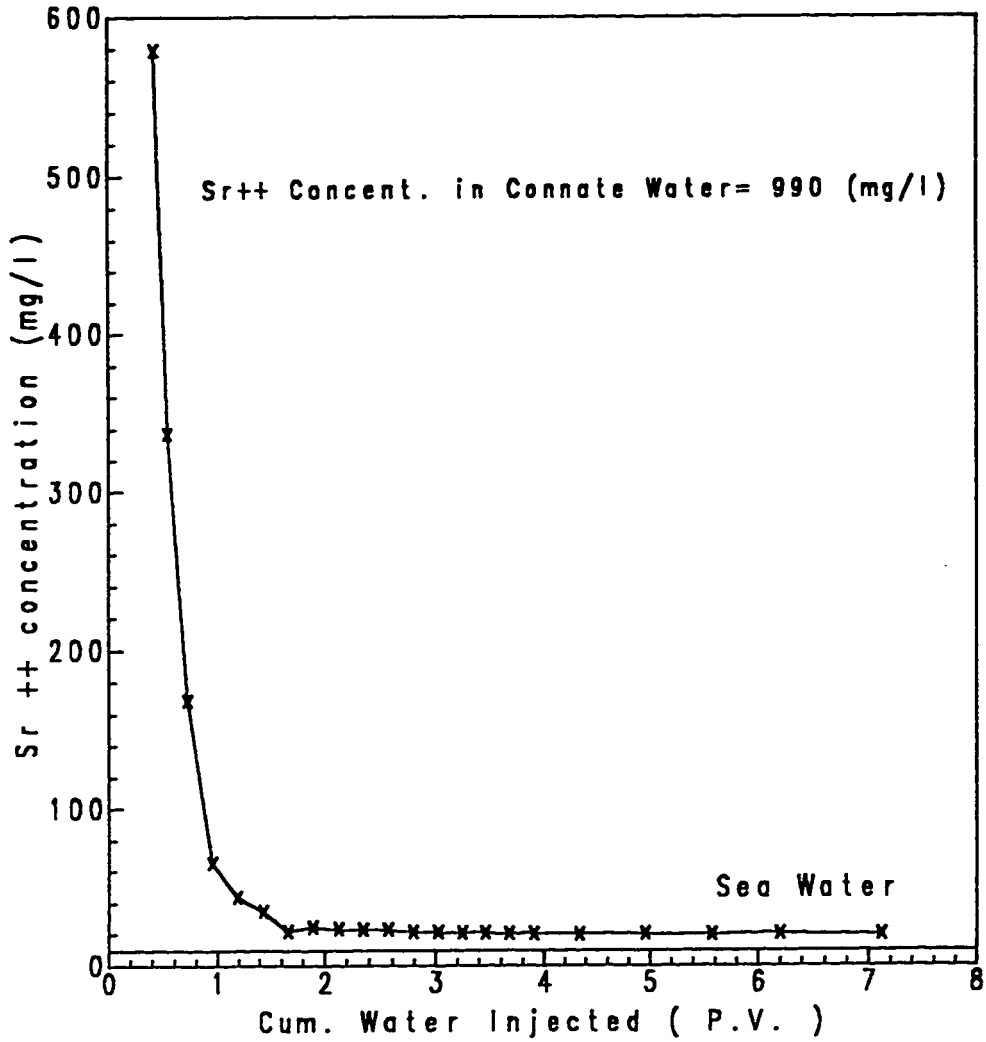


Fig. 4.25 - Sr++ Concentration vs. Cum. Water Injected for Run#7

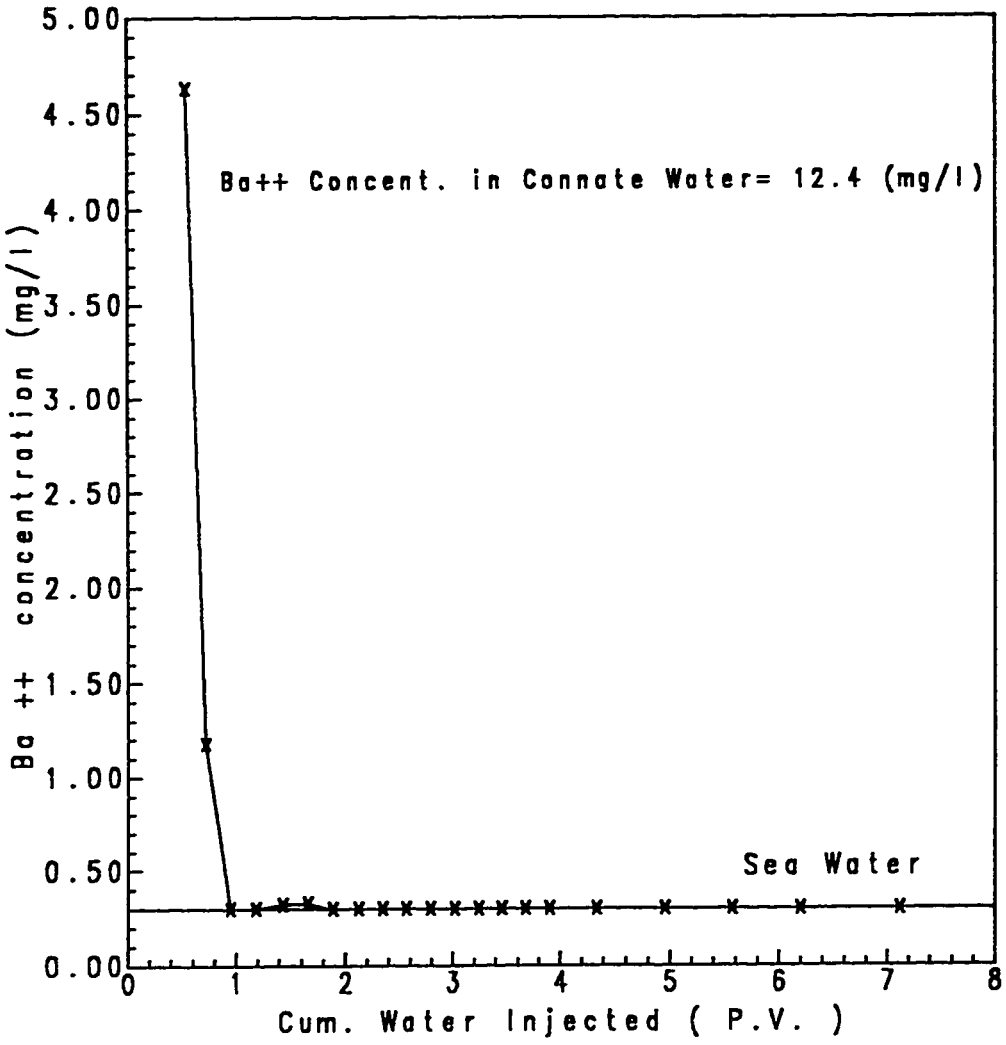


Fig. 4.26 - Ba++ Concentration vs. Cum. Water Injected for Run#7

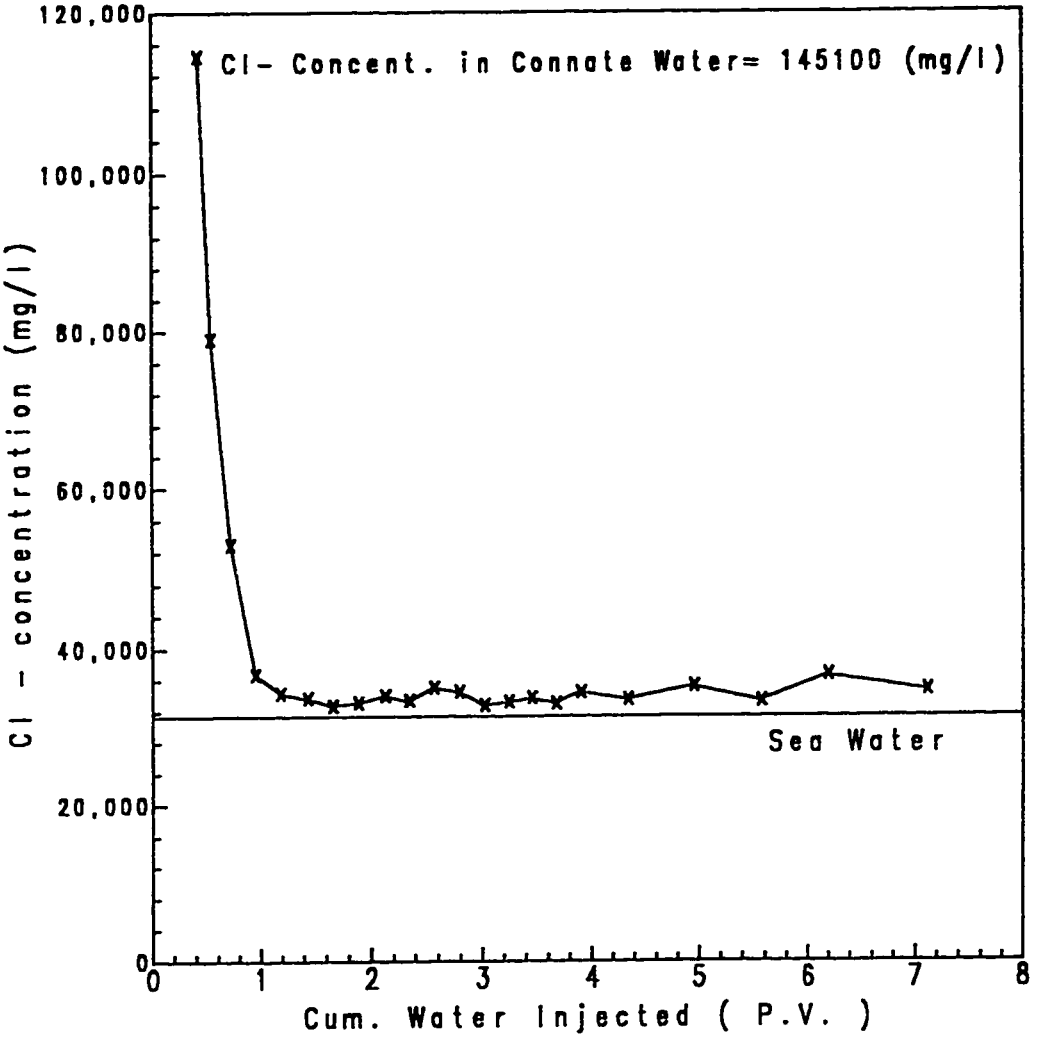


Fig. 4.27 – Cl- Concentration vs. Cum. Water Injected for Run#7

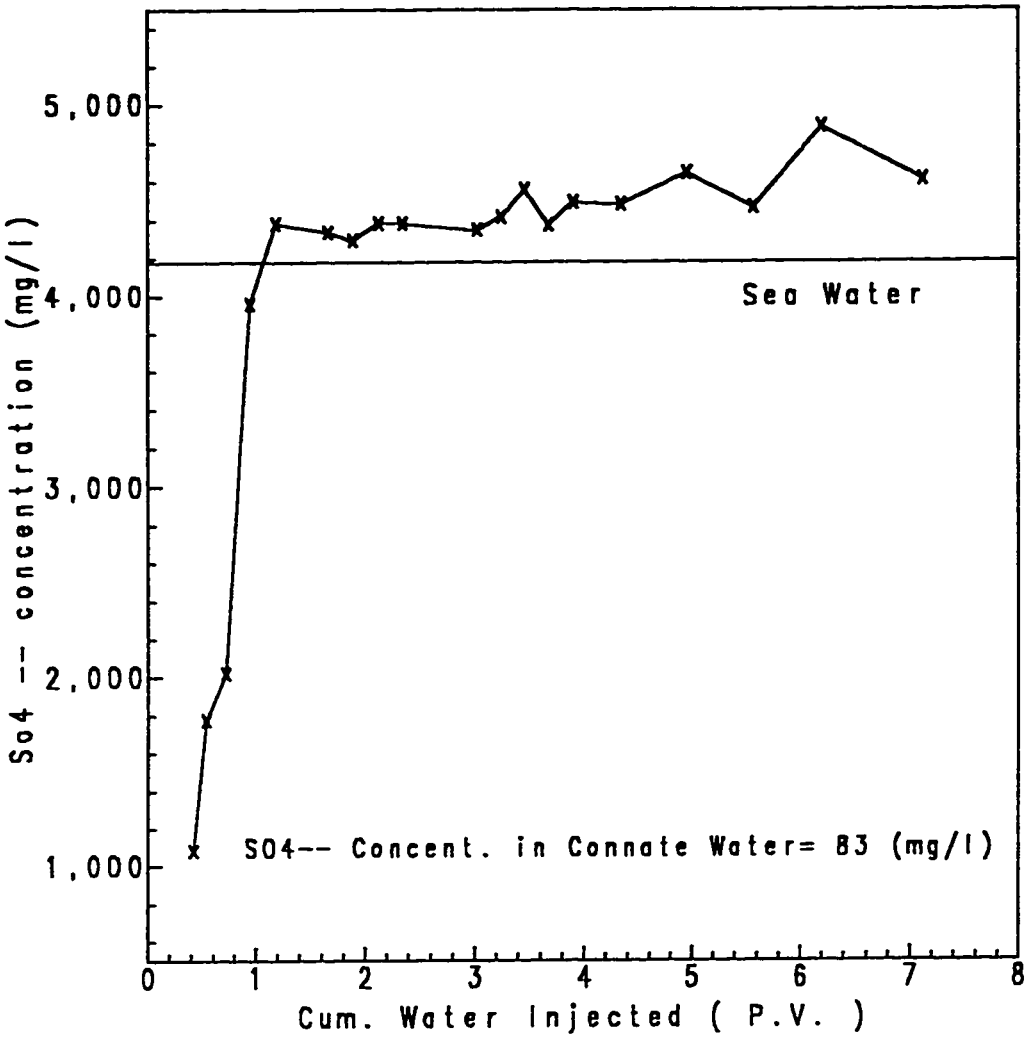


Fig. 4.28 - S04-- Concentration vs. Cum. Water Injected for Run#7

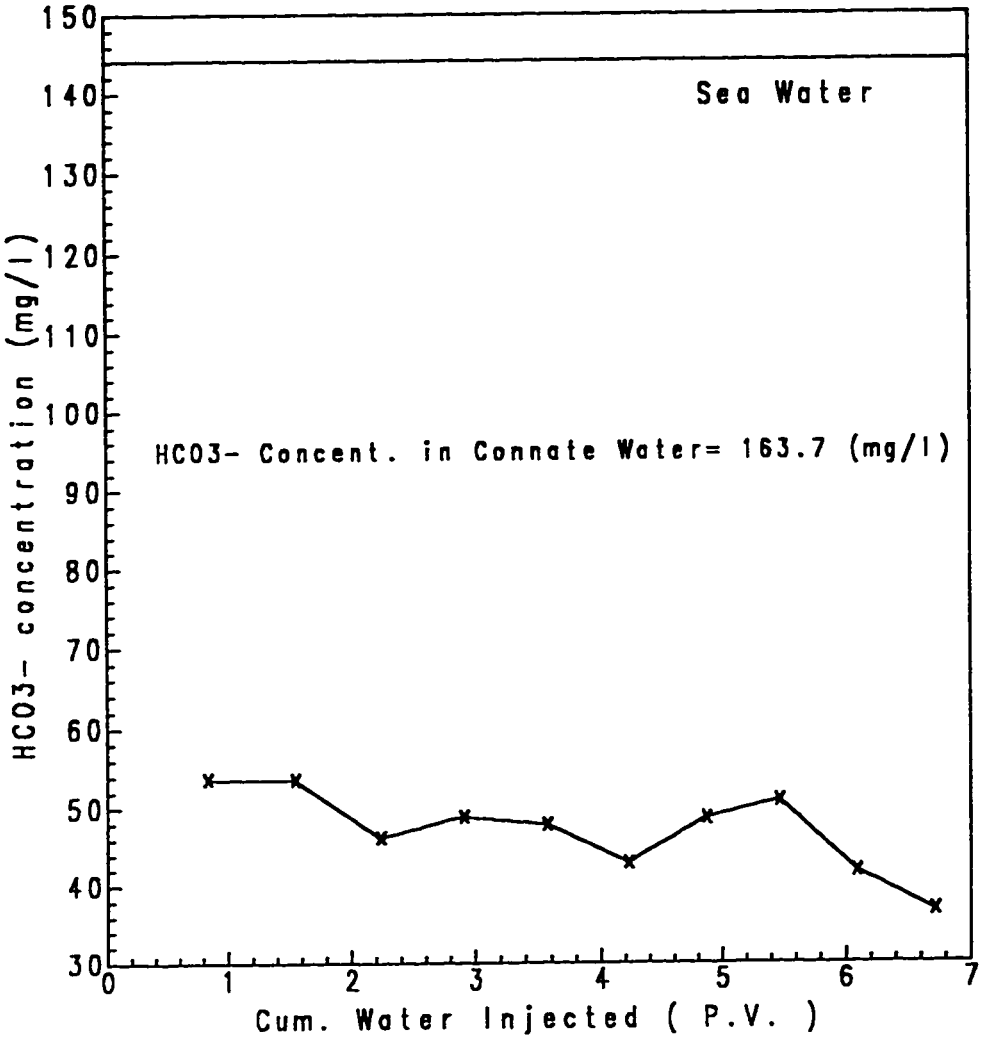


Fig. 4.29 - HCO3- Concentration vs. Cum. Water Injected for Run#7

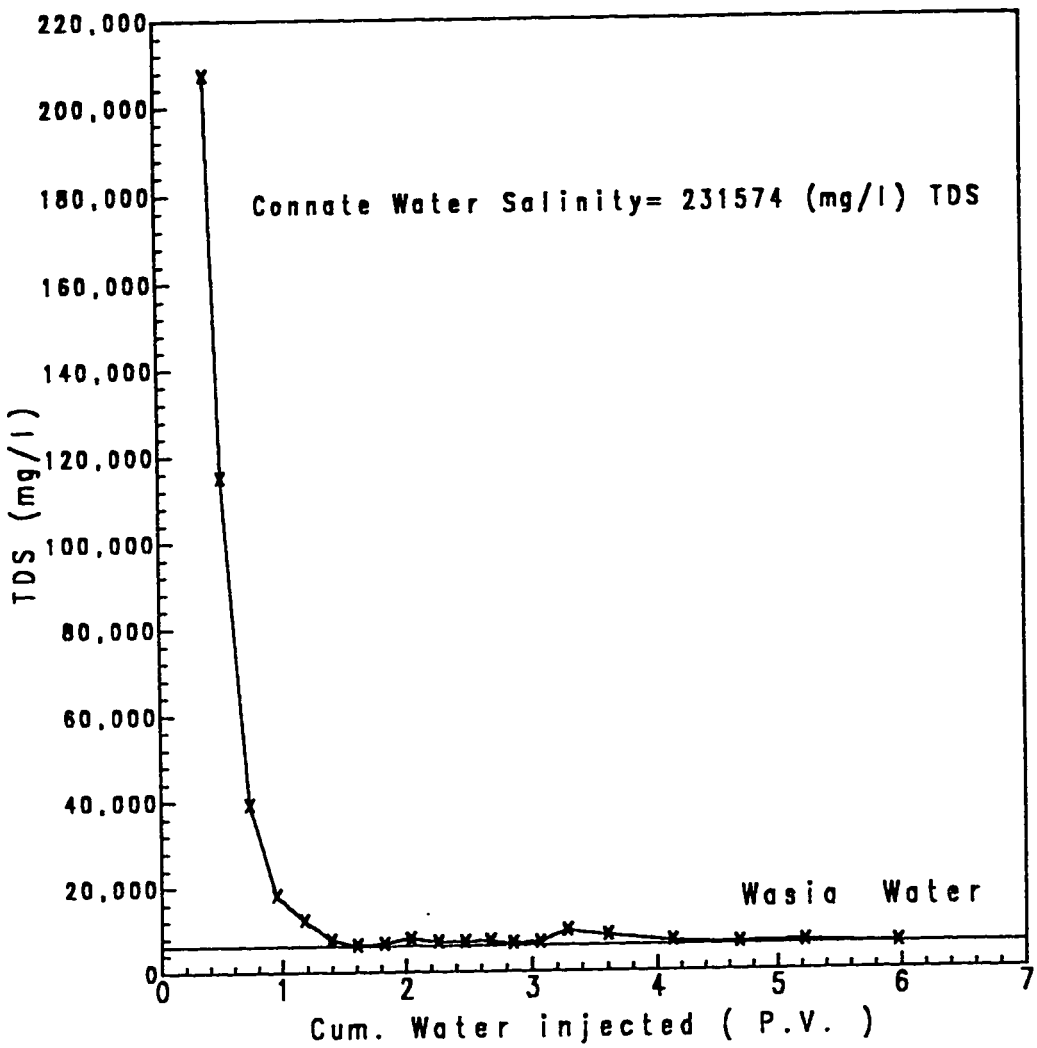


Fig. 4.30 - Total Dissolved Solids vs. Cum. Water Injected for Run#8

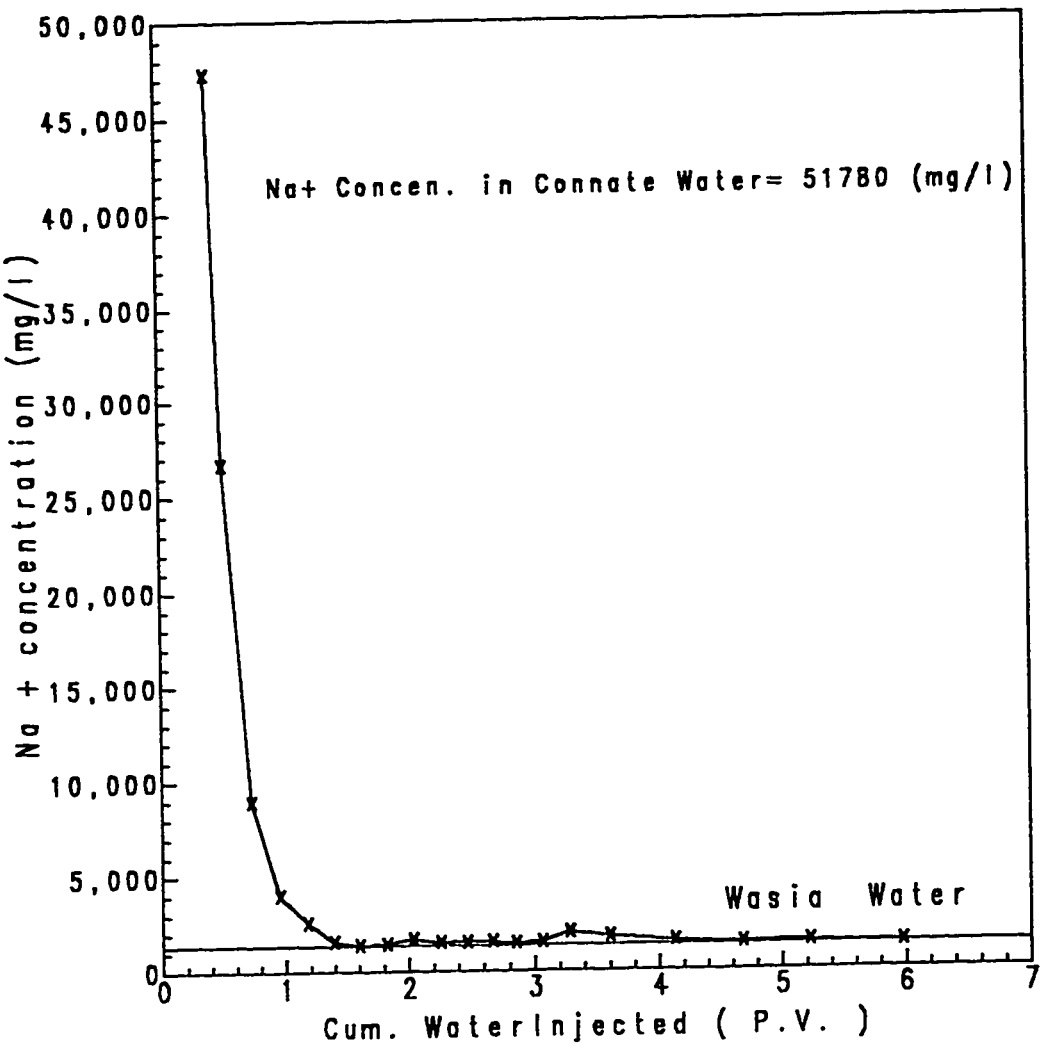


Fig. 4.31 - Na+ Concentration vs. Cum. Water Injected for Run#8

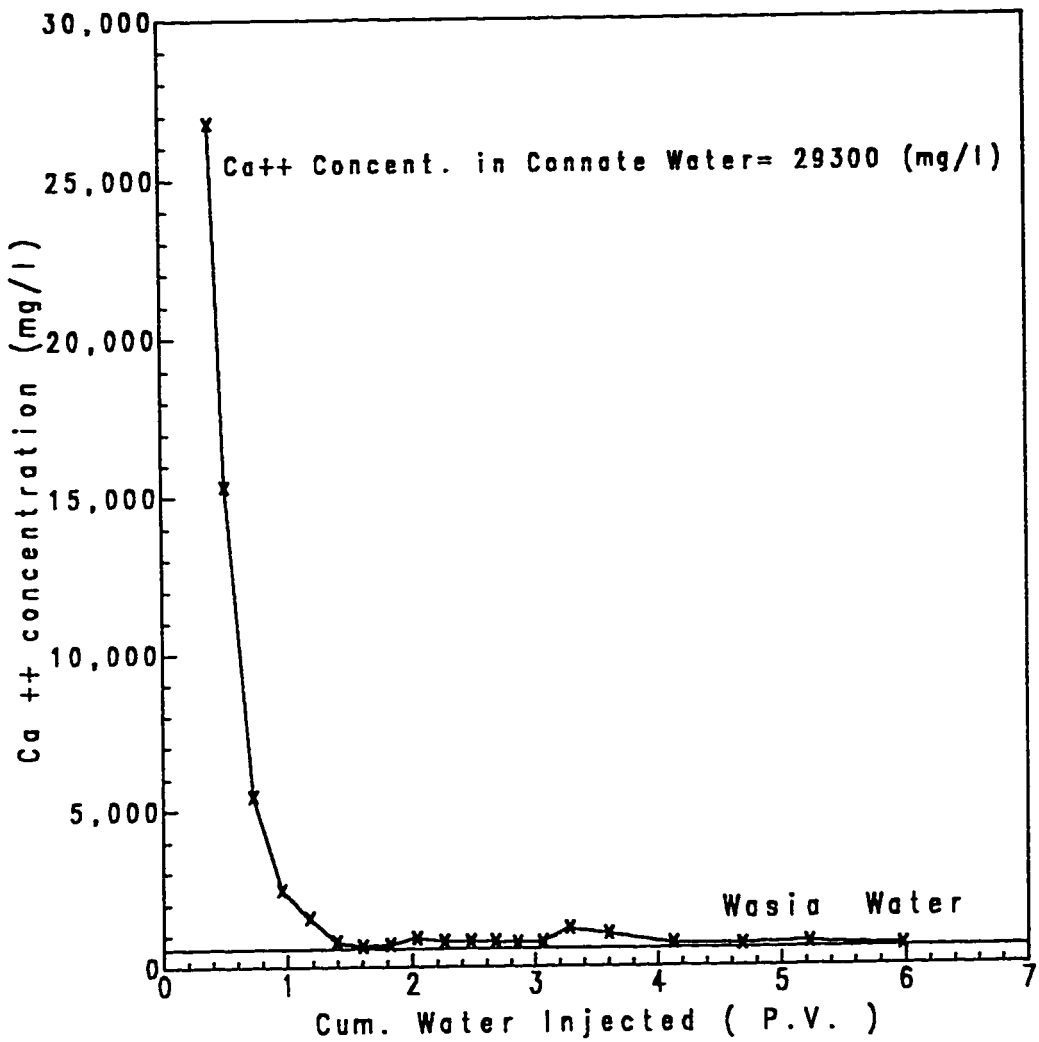


Fig. 4.32 - Ca++ Concentration vs. Cum. Water Injected for Run#8

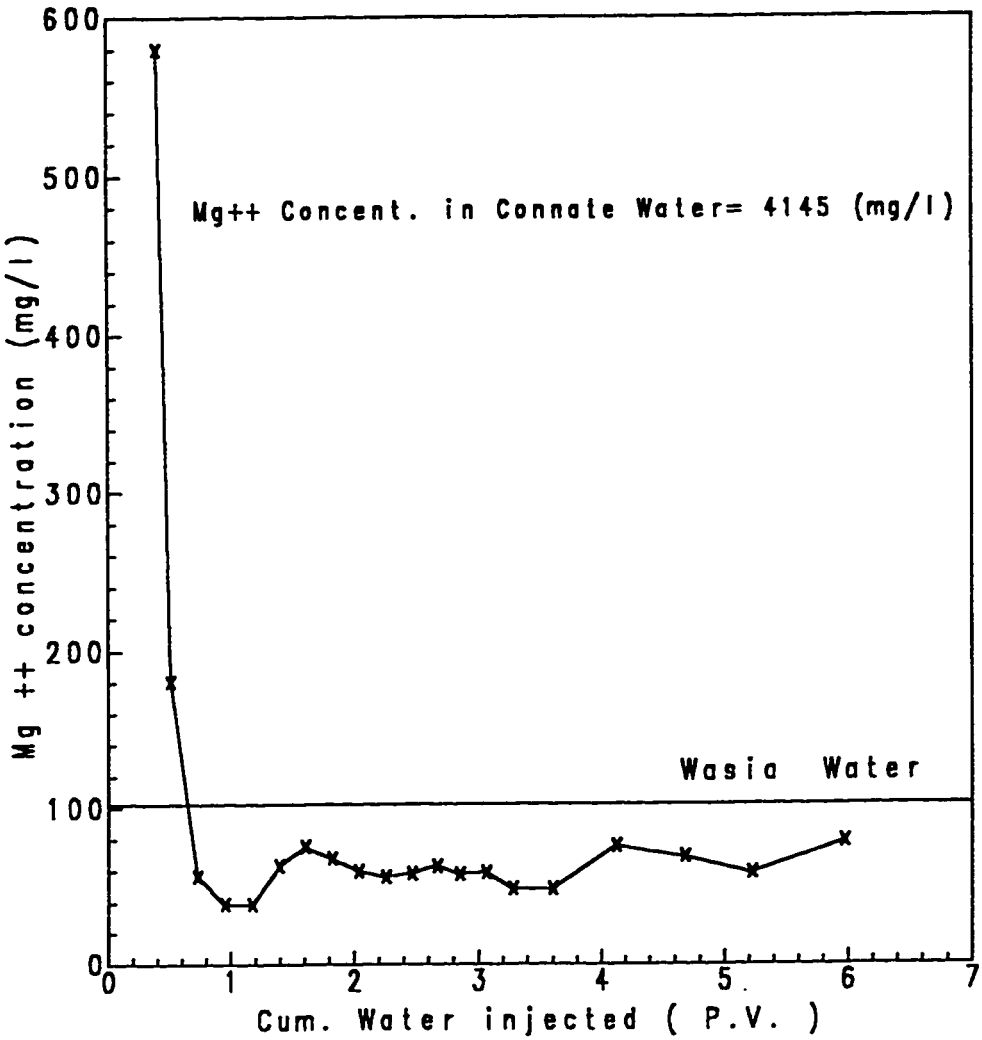


Fig. 4.33 - Mg++ Concentration vs. Cum. Water Injected for Run#8

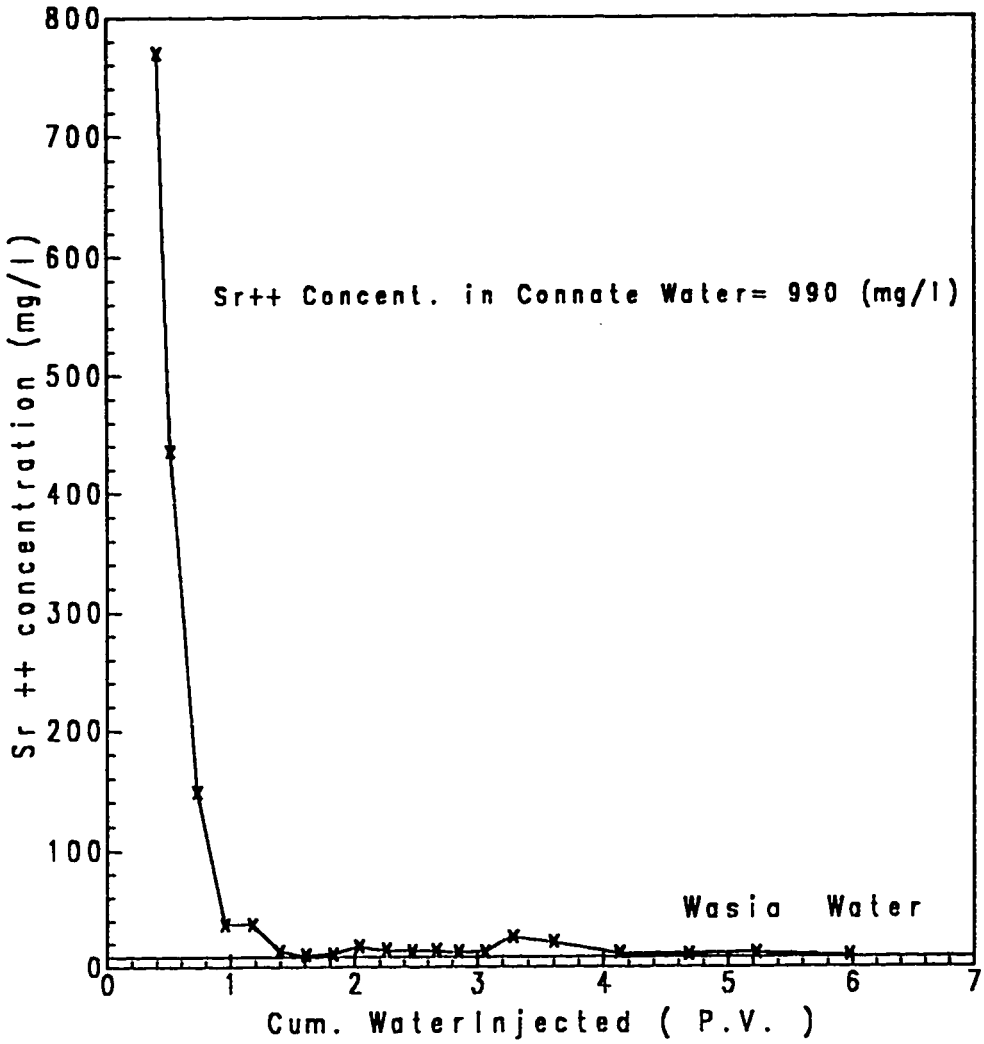


Fig. 4.34 – Sr++ Concentration vs. Cum. Water Injected for Run#8

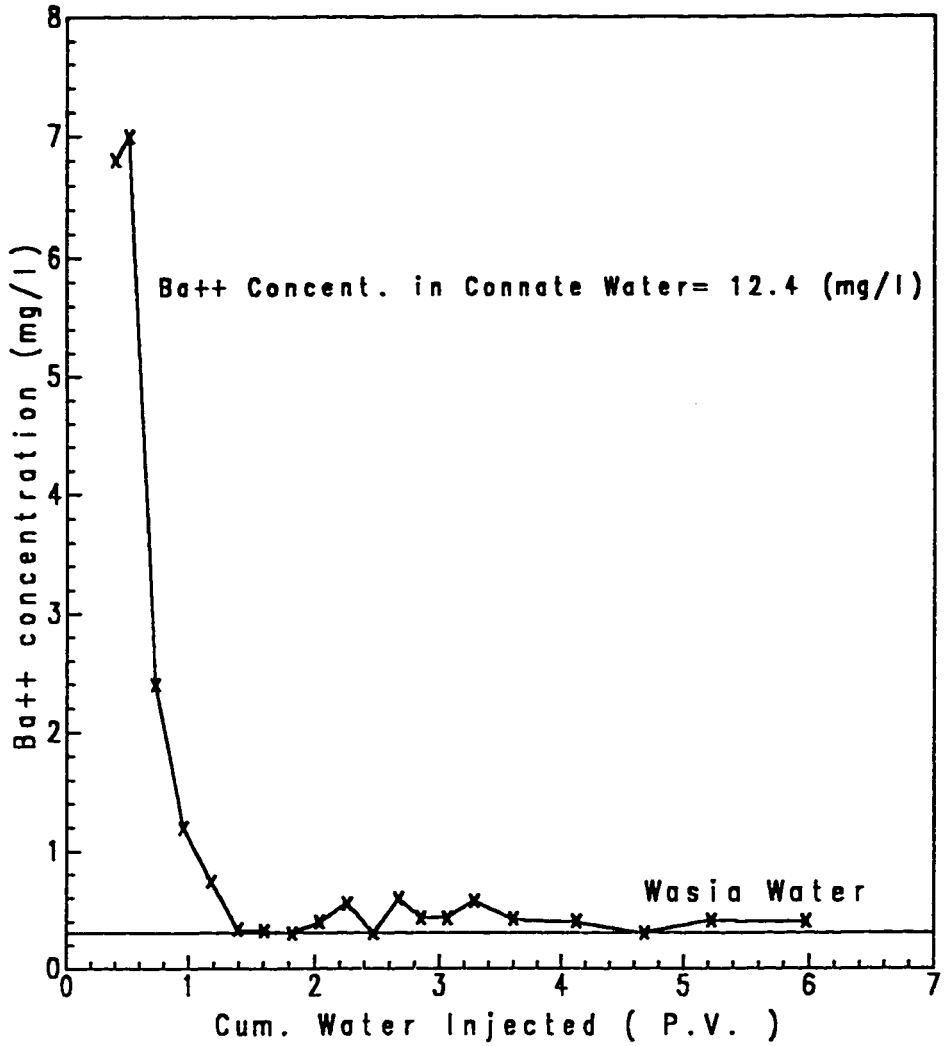


Fig. 4.35 – Ba++ Concentration vs. Cum. Water Injected for Run#8

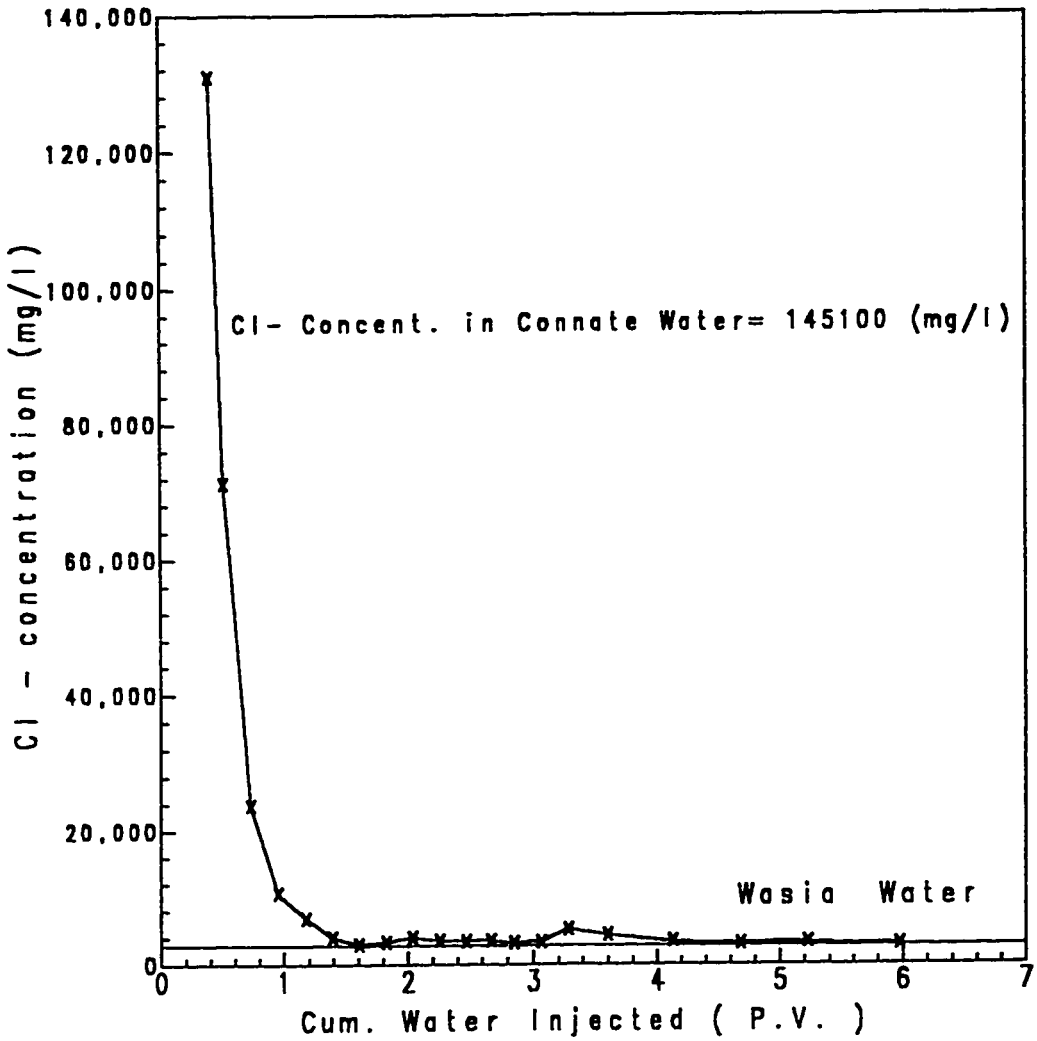


Fig. 4.36 - Cl- Concentration vs. Cum. Water Injected for Run#8

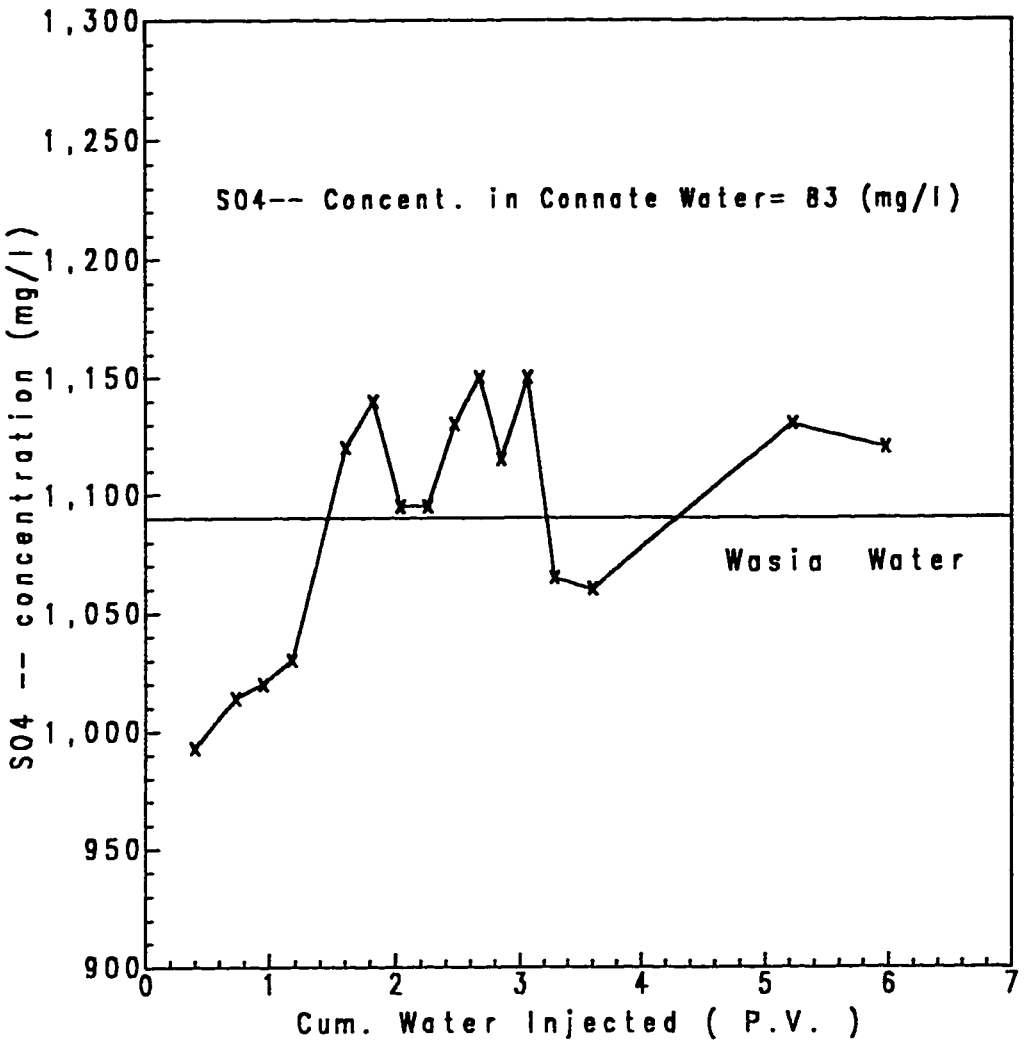


Fig. 4.37 - SO4-- Concentration vs. Cum. Water Injected for Run#8

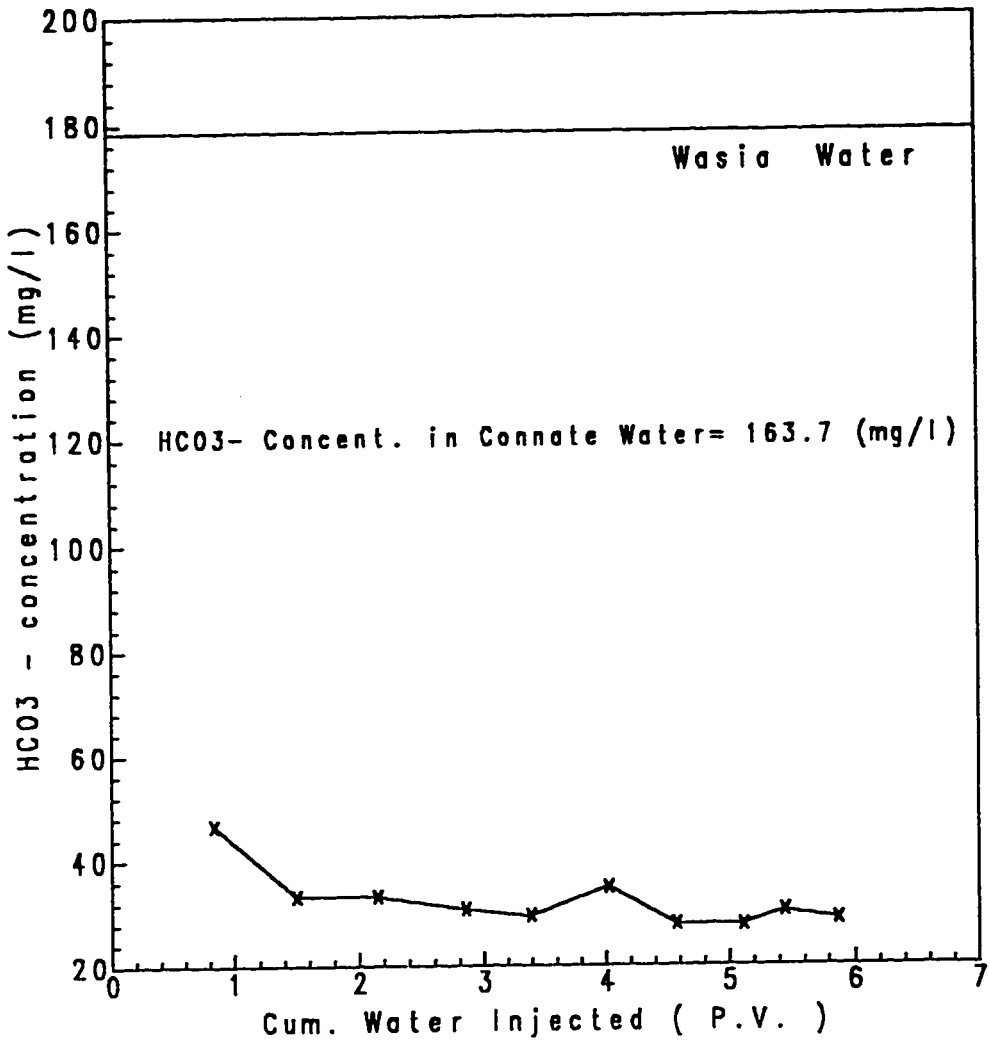


Fig. 4.38 - HCO3- Concentration vs. Cum. Water Injected for Run#8

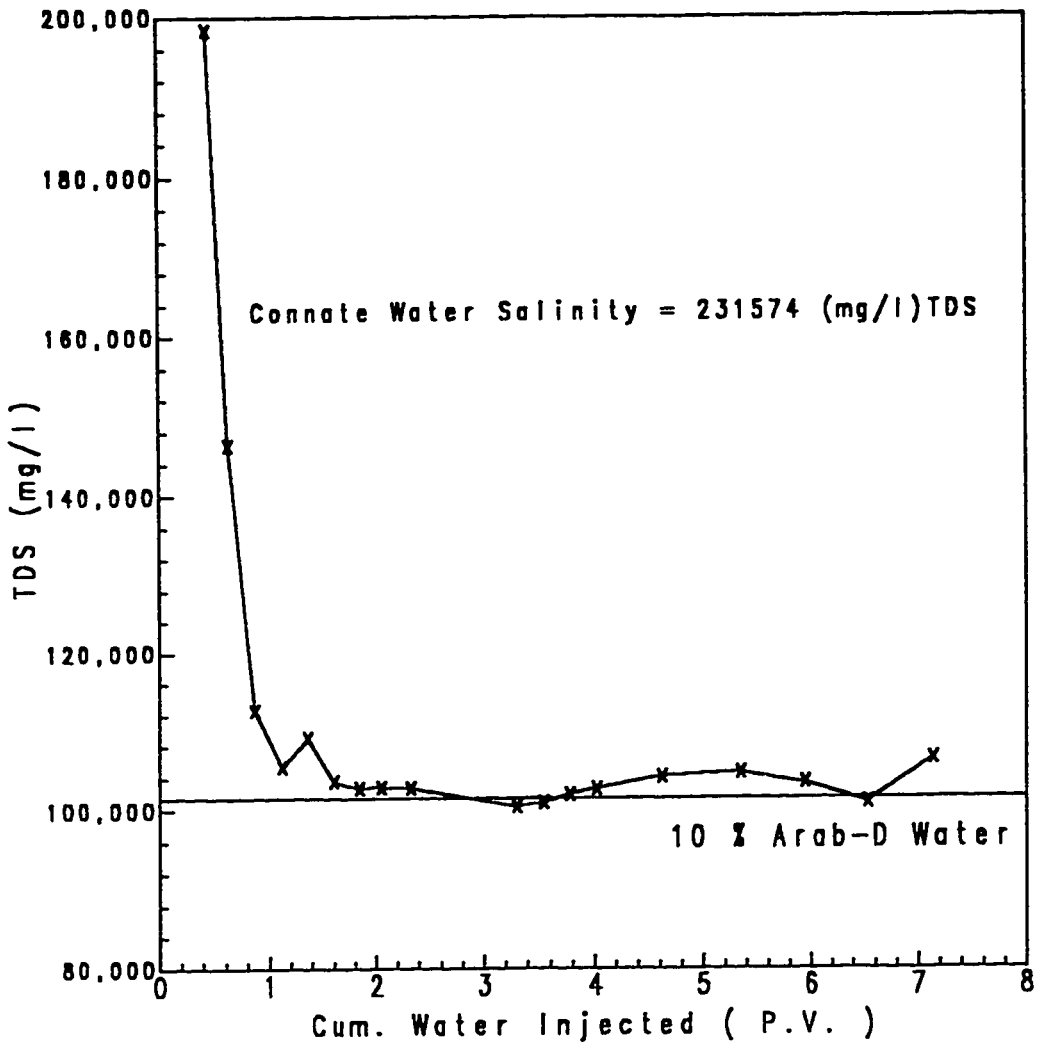


Fig. 4.39 – Total Dissolved Solids vs. Cum. Water Injected for Run#9

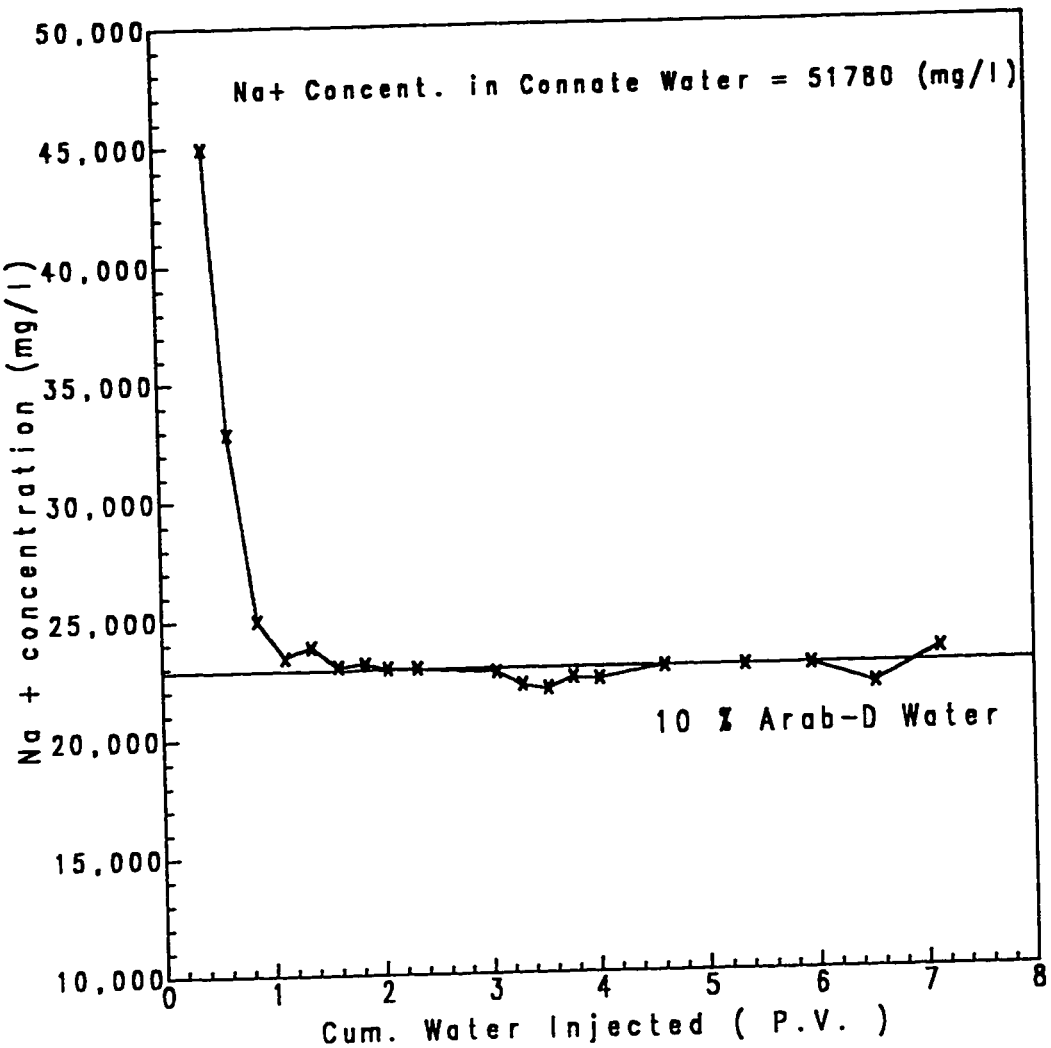


Fig. 4.40 – Na+ Concentration vs. Cum. Water Injected for Run#9

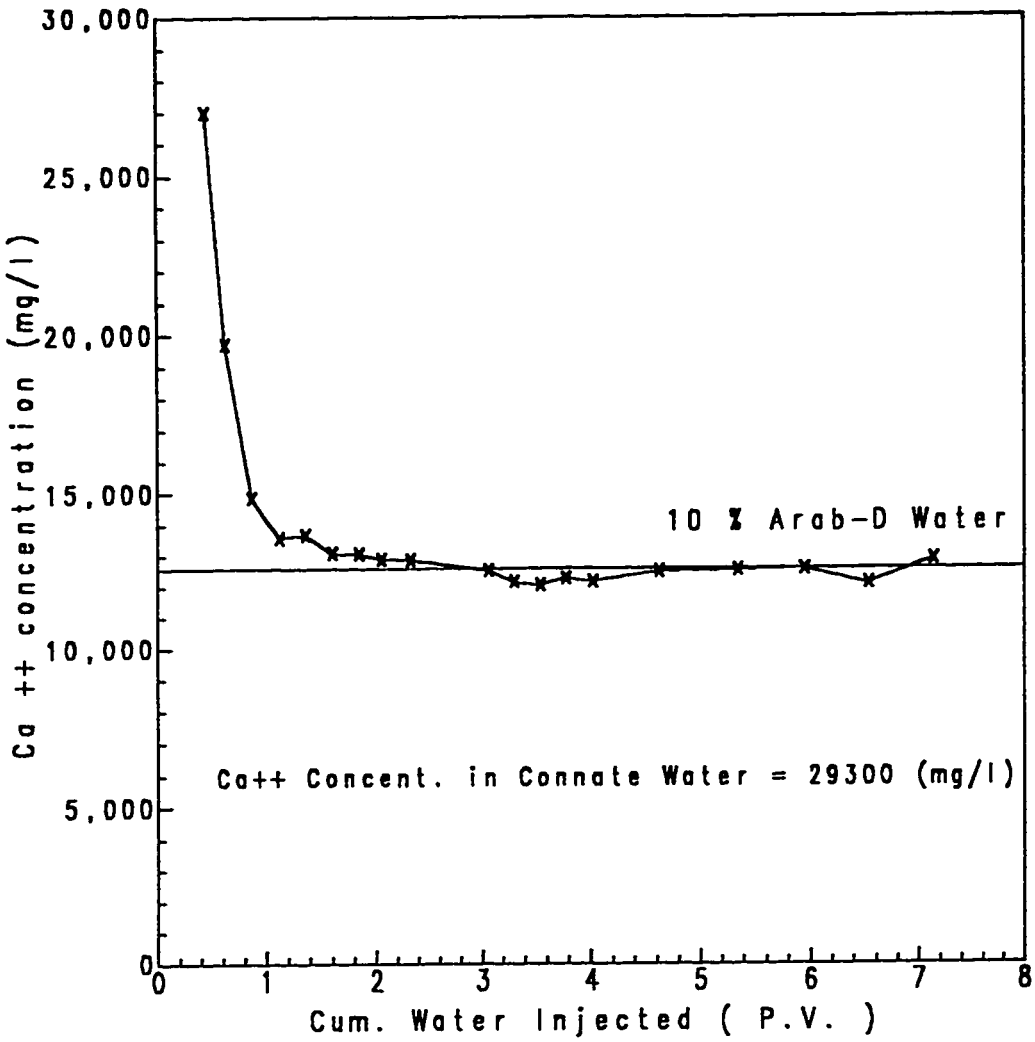


Fig. 4.41 -Ca++ Concentration vs. Cum. Water Injected for Run#9

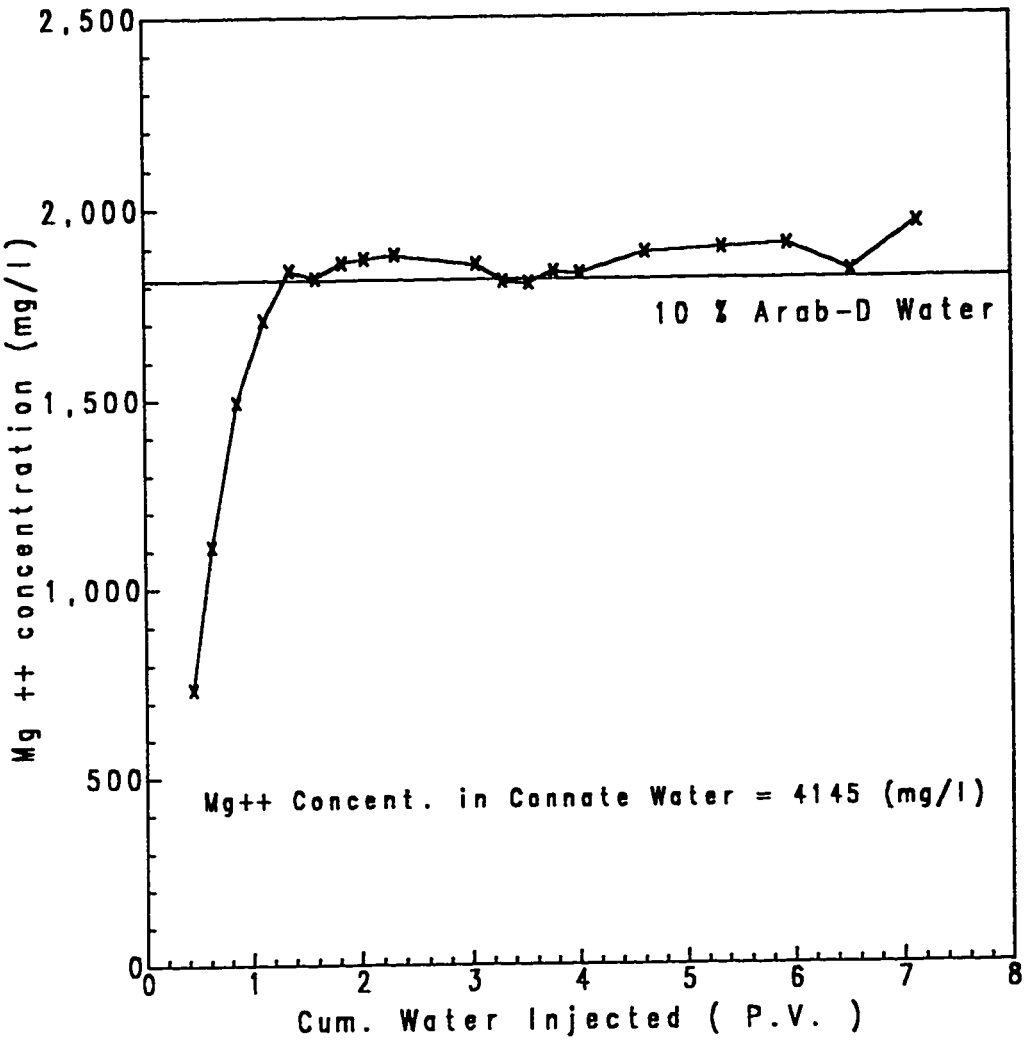


Fig. 4.42 - Mg++ Concentration vs. Cum. Water Injectedfor Run#9

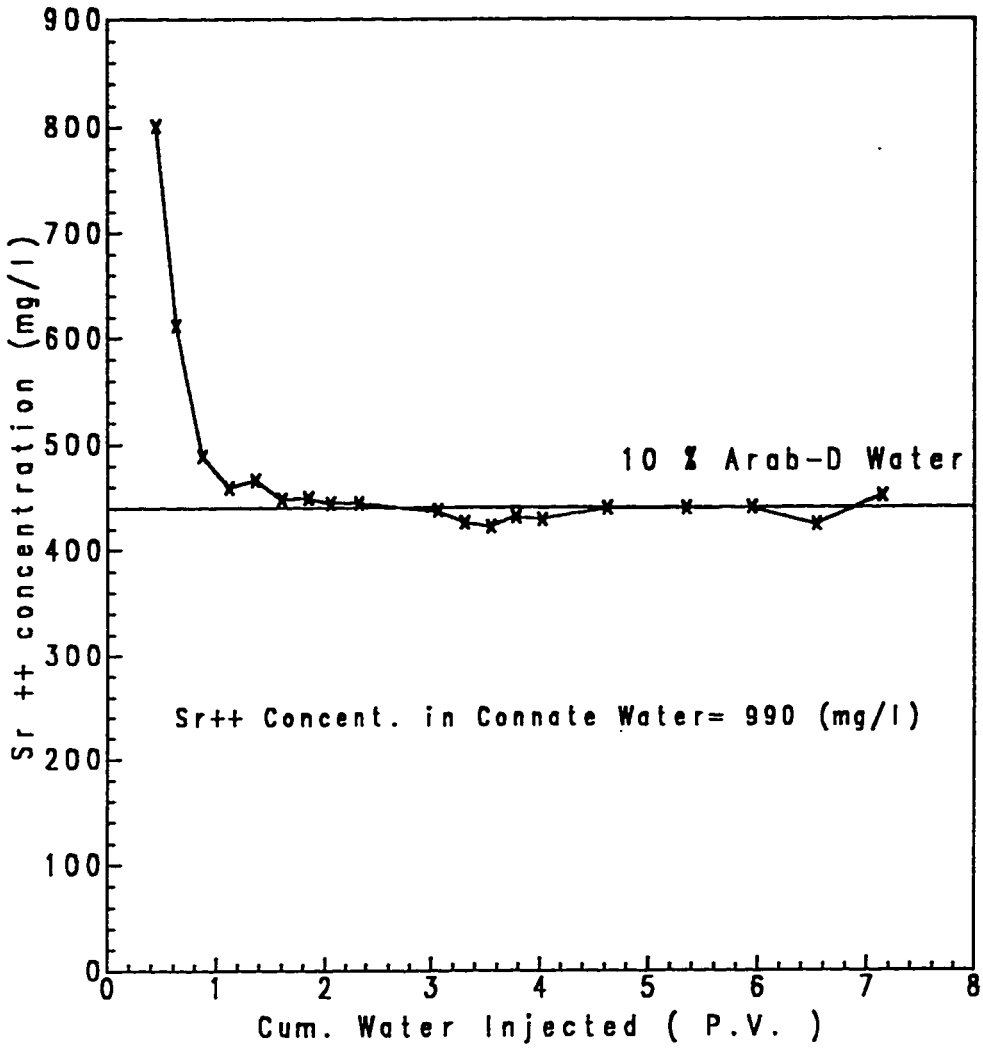


Fig. 4.43 - Sr++ Concentration vs. Cum. Water Injected for Run#9

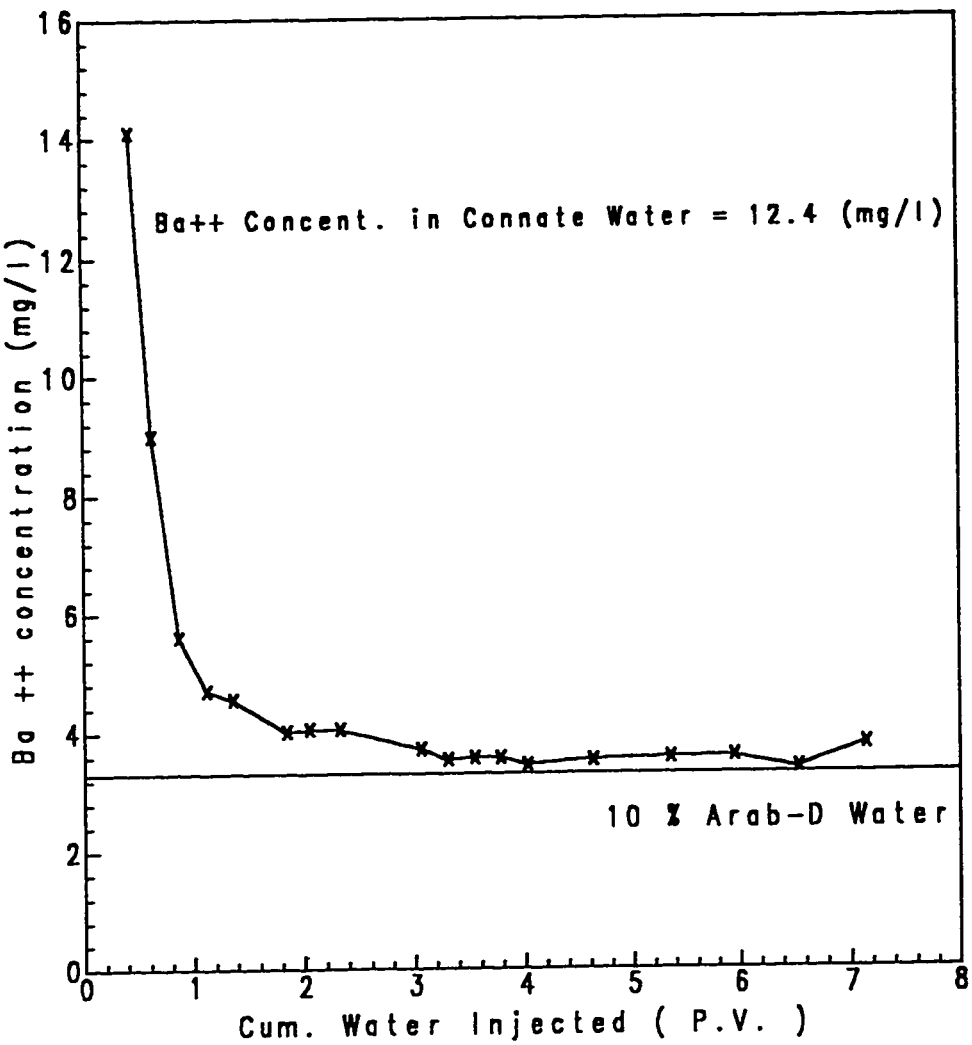


Fig. 4.44 – Ba++ Concentration vs. Cum. Water Injected for Run#9

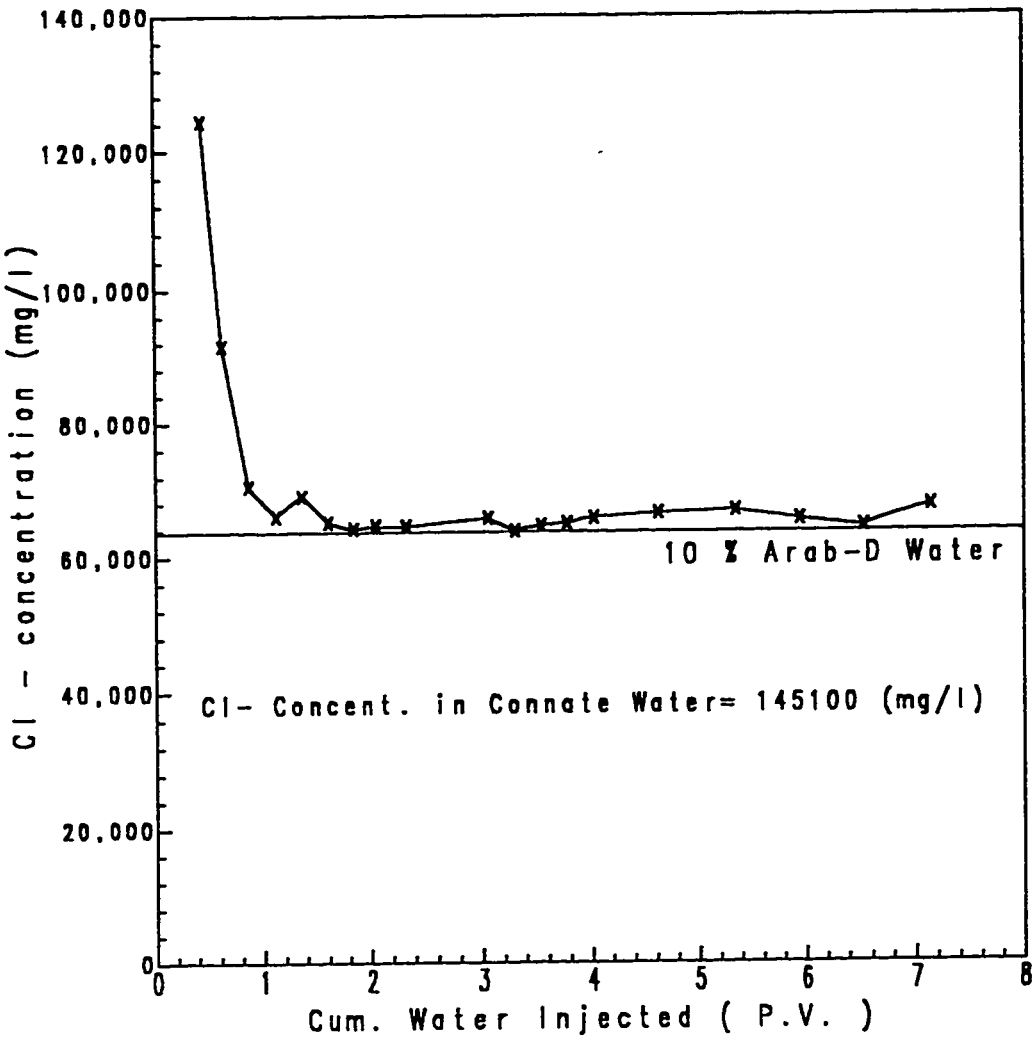


Fig. 4.45 - Cl- Concentration vs. Cum. Water Injected for Run#9

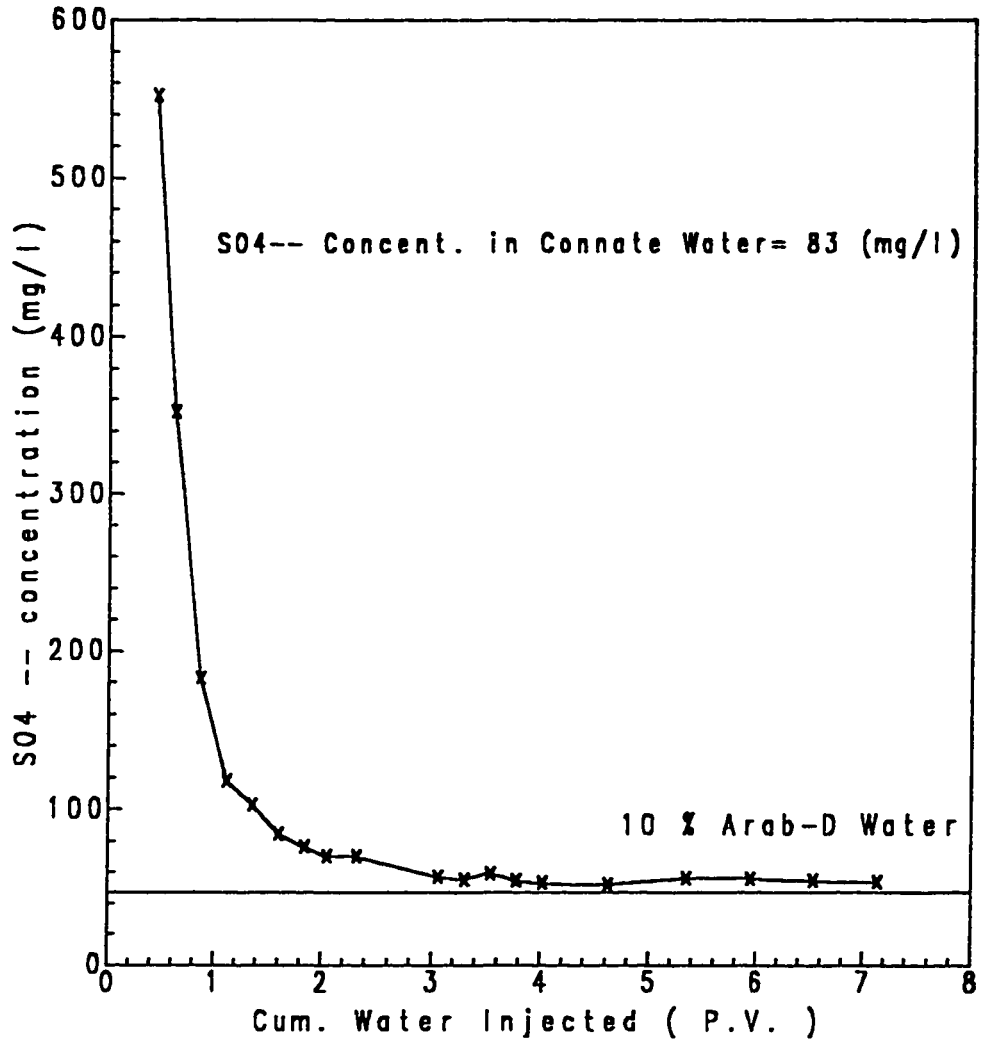


Fig. 4.46 - SO4-- Concentration vs. Cum. Water Injected for Run#9

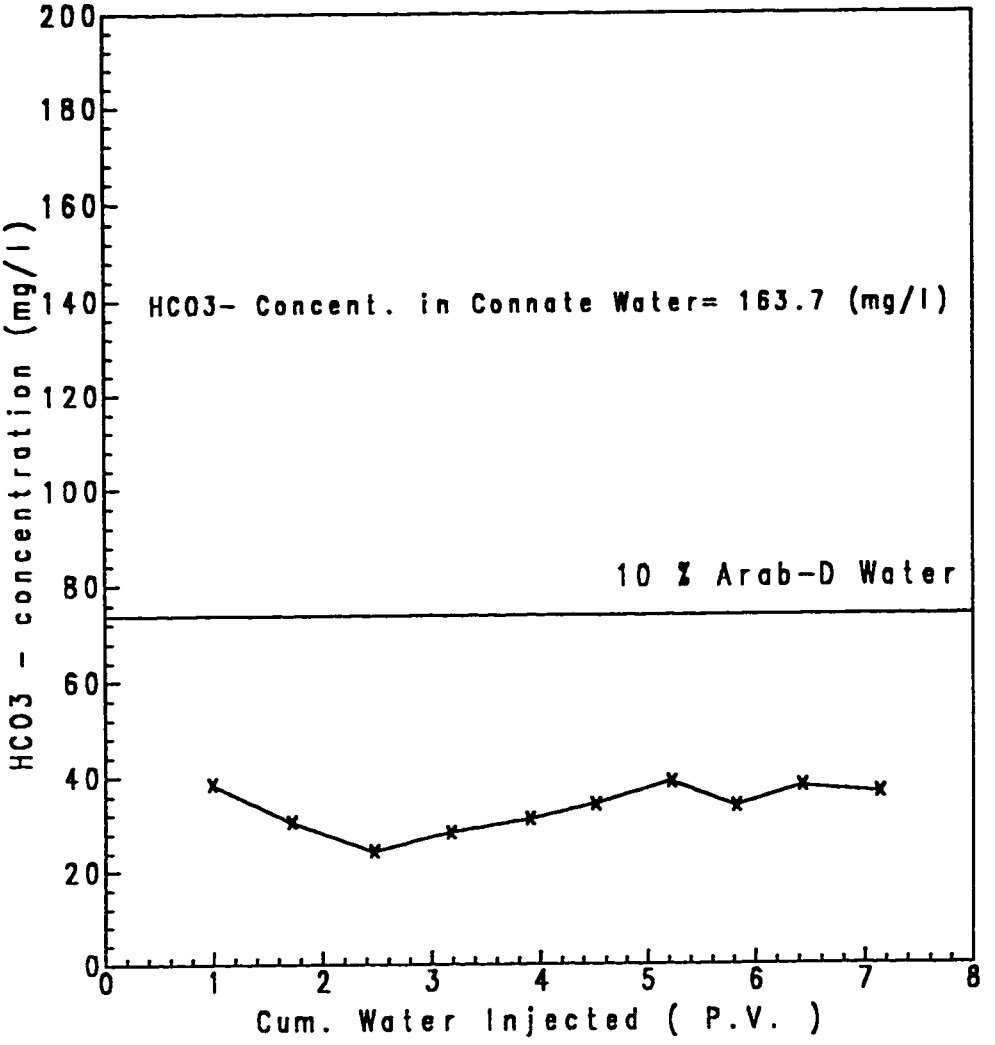


Fig. 4.47 - HCO3- Concentration vs. Cum. Water Injected for Run#9

represents the concentration of that ion in the injected water. The concentration in the connate water is also given on the plot.

The following can be inferred from all the plots:

(1) All the ions except $Mg^{++}$ and $HCO_3^-$ showed expected variation of ion concentration (similar to the NaCl brines) as the floods proceed. The ion concentration starts at a value close to the concentration of the connate water, goes sharply to the concentration of the injected water after injecting 1.5 P.V., then stays constant until the end of the run.

(2) $Mg^{++}$ exhibited a different behavior than other ions in all the runs. For both Run # 7 and Run # 9, its concentration starts from a value that is less than the concentration of both the injected water and the connate water. Then it increases to the concentration of the injected water after 1.5 P.V. as shown in Fig.4.24 and Fig. 4.42. In Run # 8, the starting concentration of $Mg^{++}$ was also low (580 mg/l) but because of the low concentration of $Mg^{++}$ in Wasia water (102 mg/l), it showed a decreasing trend towards a concentration a little bit less than the concentration of Wasia water as shown in Fig. 4.33.

(3) $HCO_3^-$ shows a constant and low concentration (lower than both the

injected and connate waters) in all the runs as shown in Figs. 4.29, 4.38 and 4.47.

#### *4.5.2.2 Discussion*

The loss of $Mg^{++}$ at the beginning of water production is unlikely to be an incompatibility problem for the following reasons : First, the compatibility tests did not show any $Mg^{++}$ precipitate. Second, the higher concentration of $Ca^{++}$ in connate water gives it the priority to form precipitate rather than $Mg^{++}$. Finally, all the three runs where three different waters were injected exhibited the same phenomena of $Mg^{++}$ loss.

To check the loss of $Mg^{++}$, Run# R-7 where sea water is injected was performed as a repeatability of Run# 7. The results obtained are in agreement with Run # 7. The plots of ions concentration vs. cumulative water injected of Run # R-7 are shown in Figs. 4.48 through 4.56. Fig. 4.57 compares the $Mg^{++}$ plots of Run # 7 and Run # R-7.

The loss of $Mg^{++}$ at the start of the flood is probably due to adsorption in the Berea core samples. The Berea sandstone samples may contain some calcium carbonate ($CaCO_3$) as a cementation material. When fired at 900°C to stabilize the clay content, $CaCO_3$ decomposes to

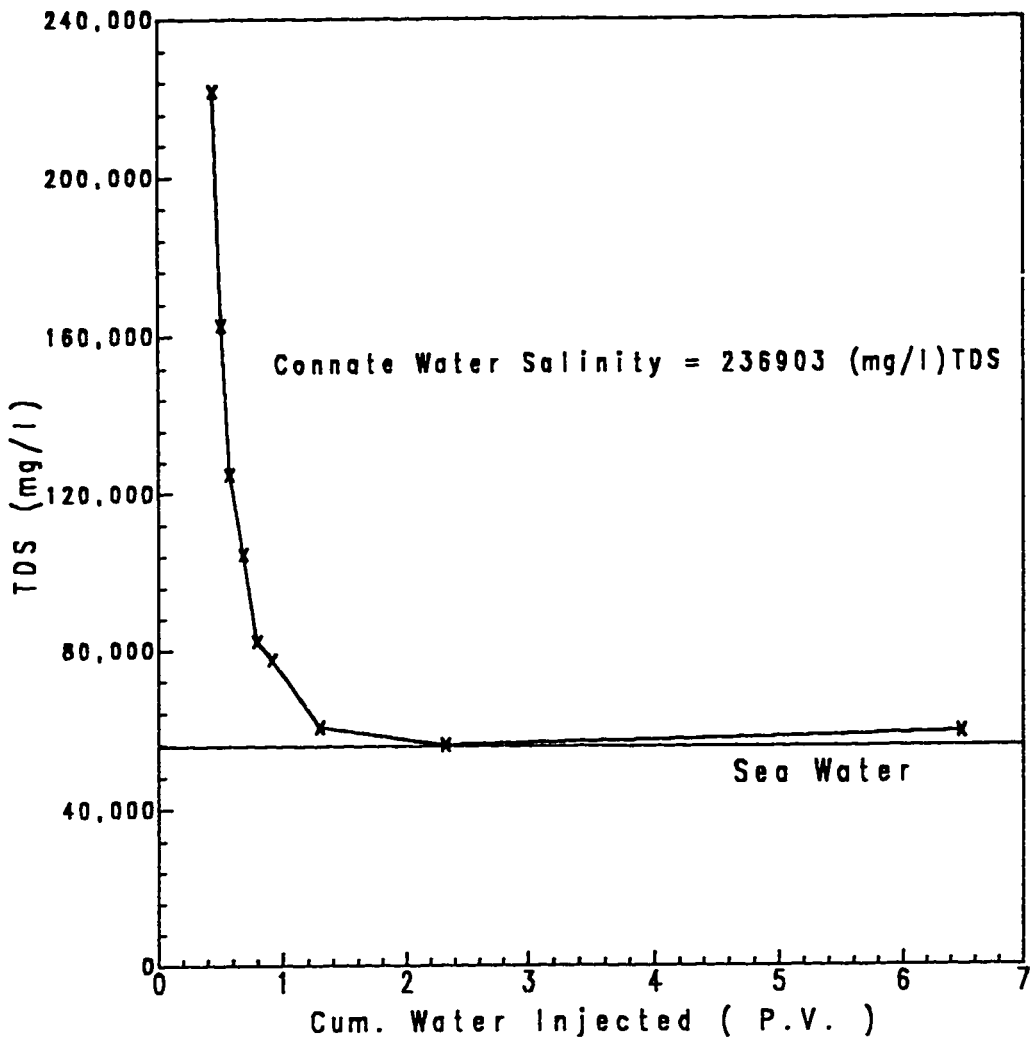


Fig. 4.48 - Total Dissolved Solids vs. Cum. Water Injected for Run#R-7

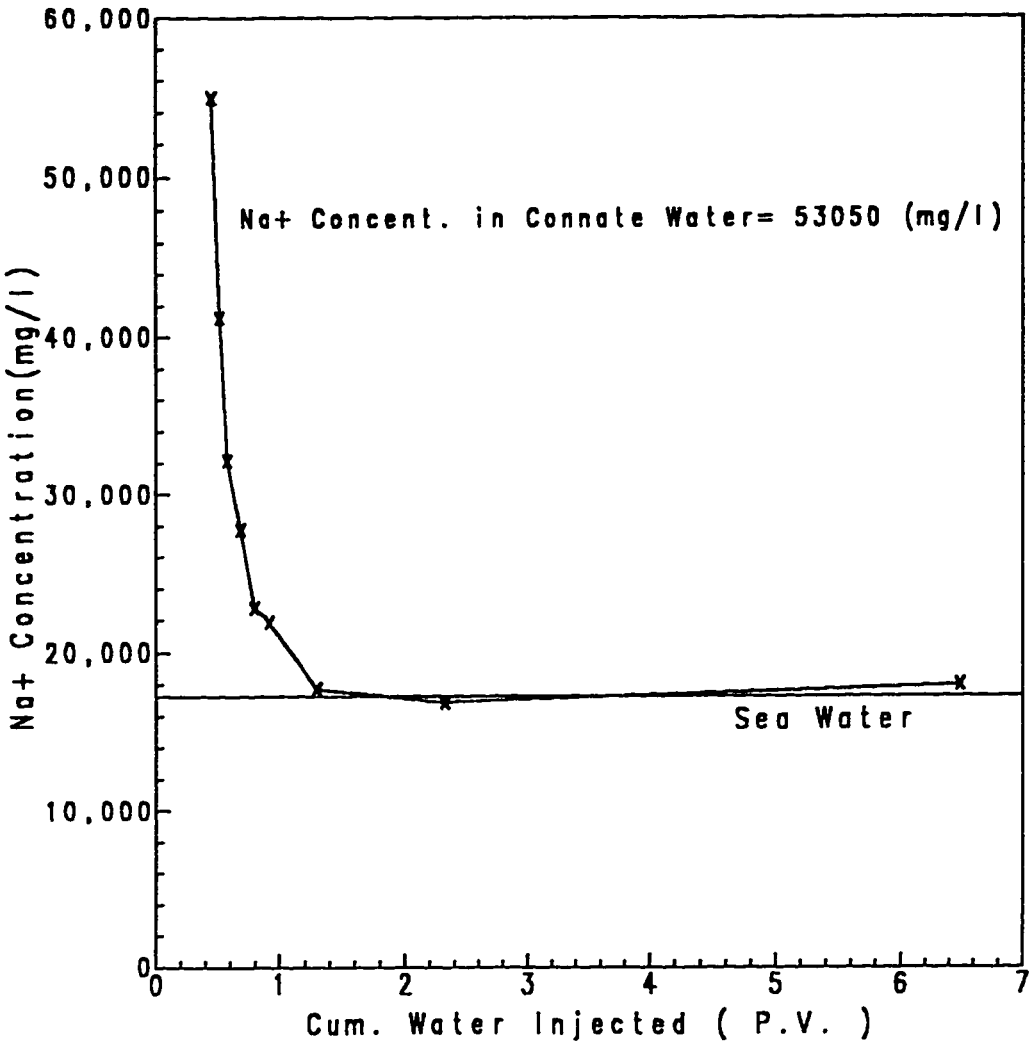


Fig. 4.49 – Na+ Concentration vs. Cum. Water Injected for Run#R-7

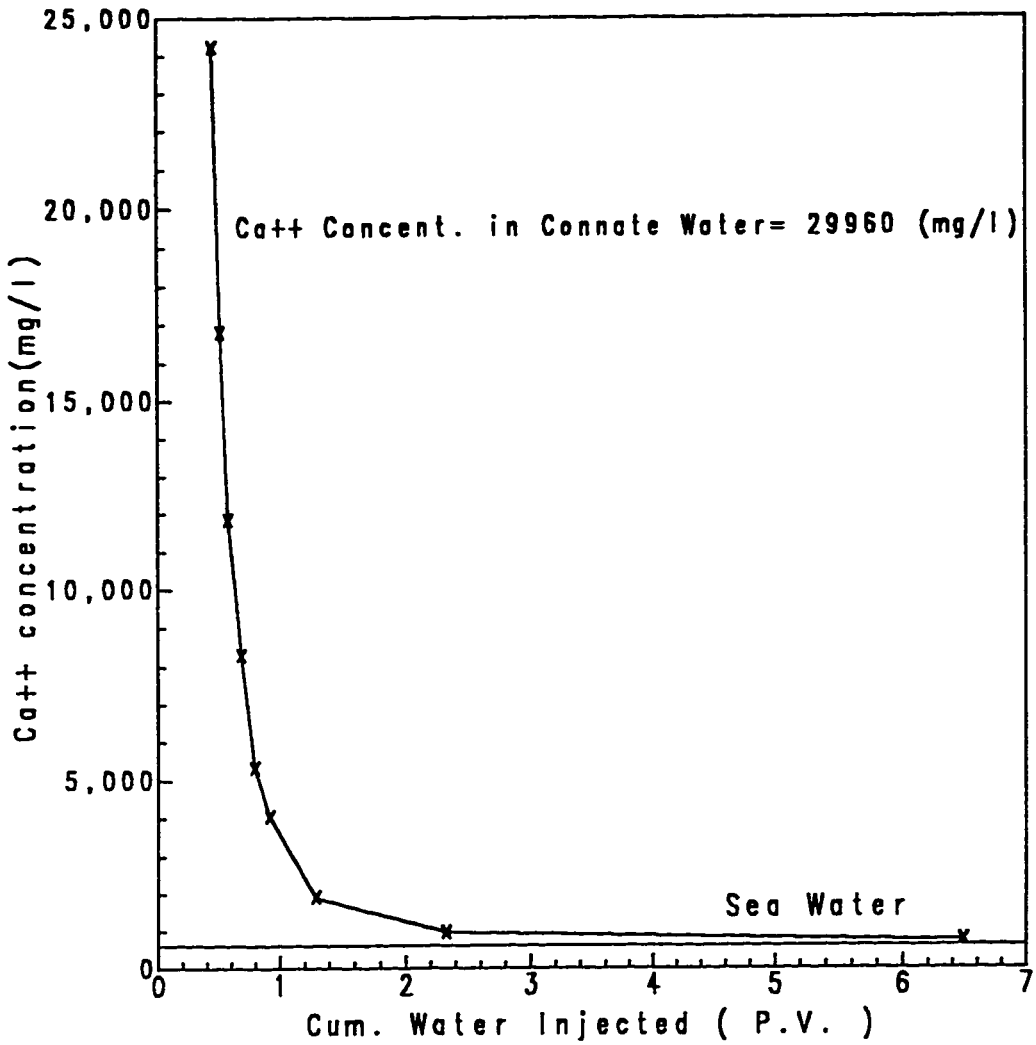


Fig. 4.50 - Ca++ Concentration vs. Cum. Water Injected for Run#R-7

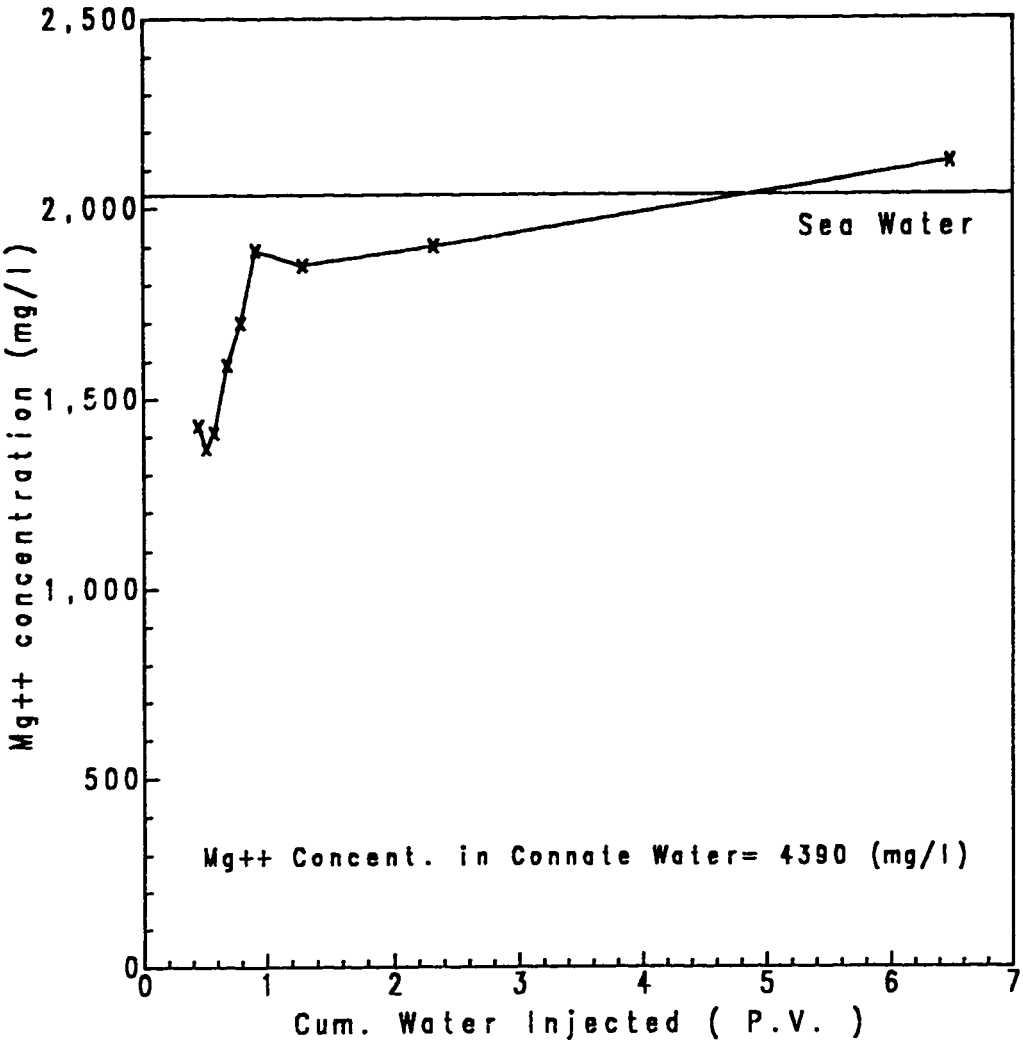


Fig. 4.51 - Mg++ Concentration vs. Cum. Water Injected for Run#R-7

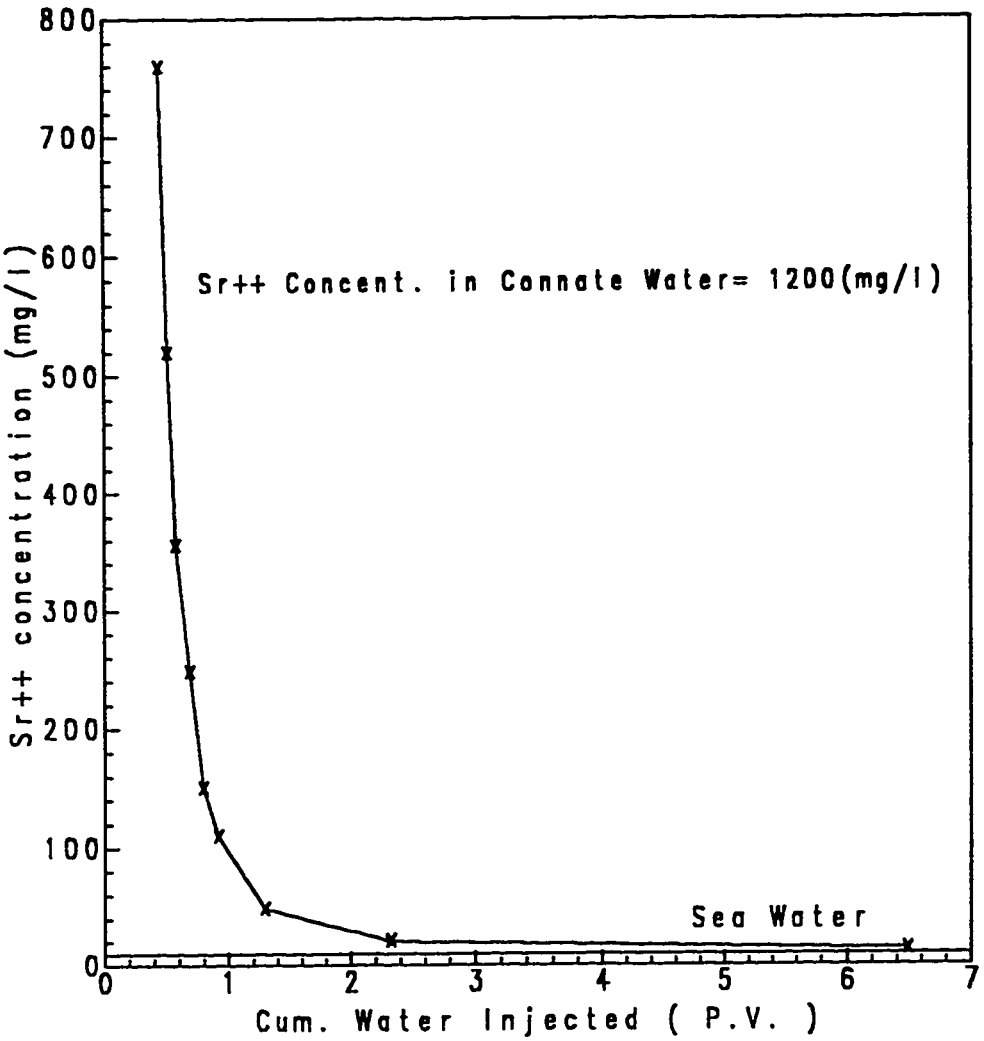


Fig. 4.52 - Sr++ Concentration vs. Cum. Water Injected for Run#R-7

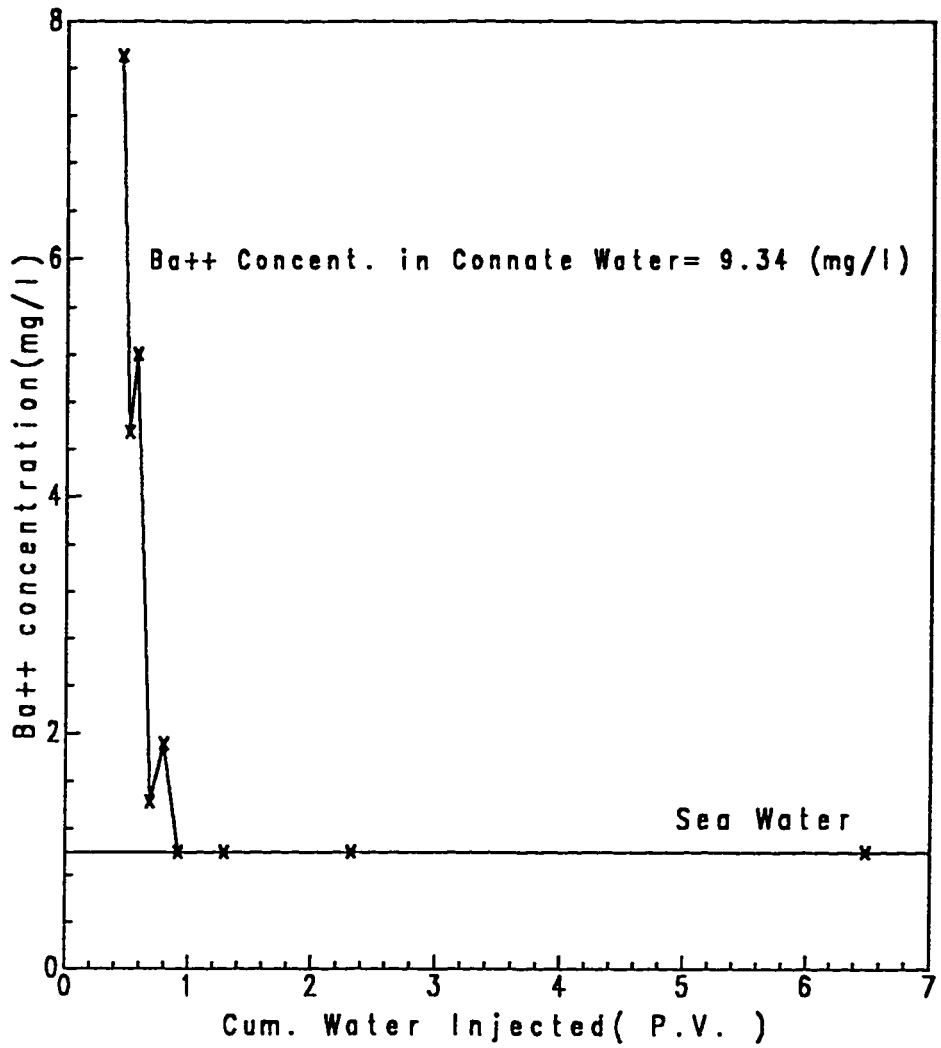


Fig. 4.53 - Ba++ Concentration vs. Cum. Water Injected for Run#R-7

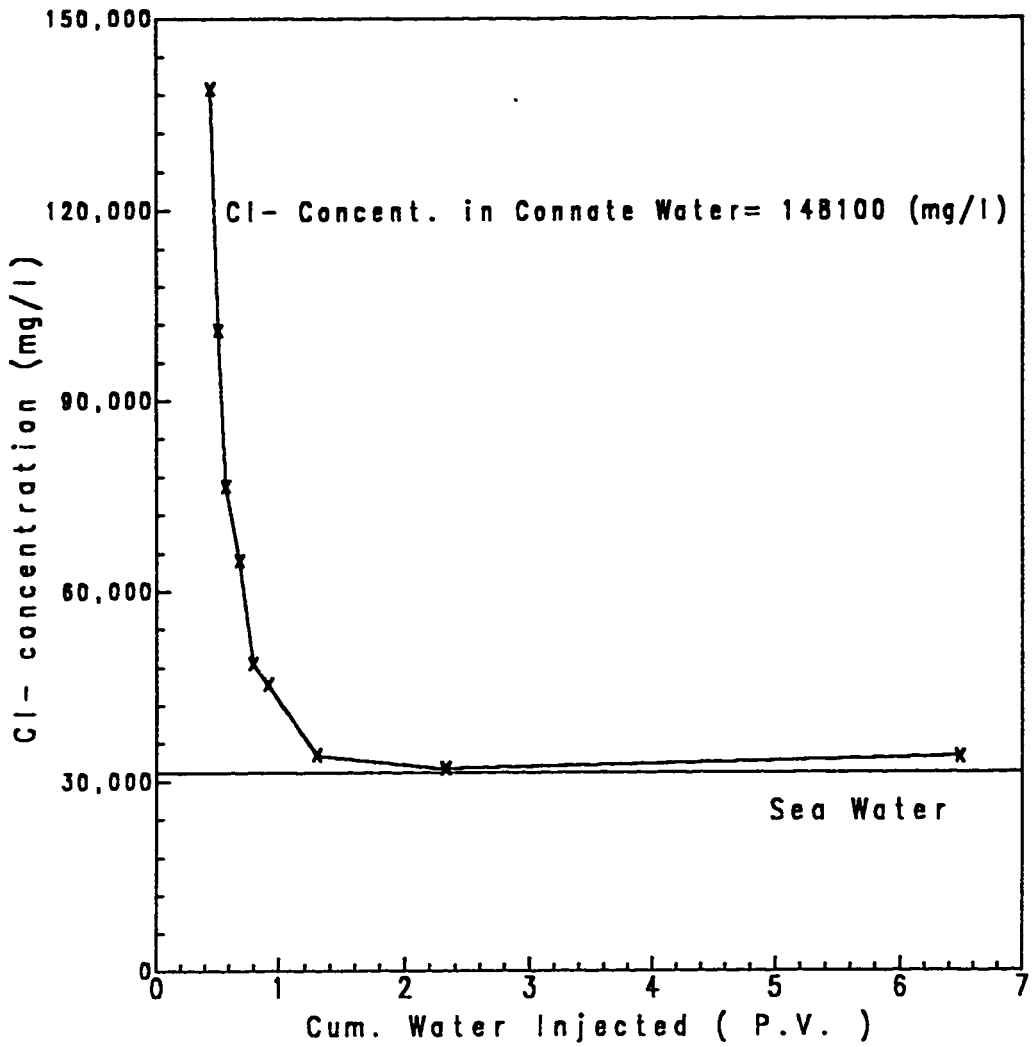


Fig. 4.54 - Cl- Concentration vs. Cum. Water Injected for Run#R-7

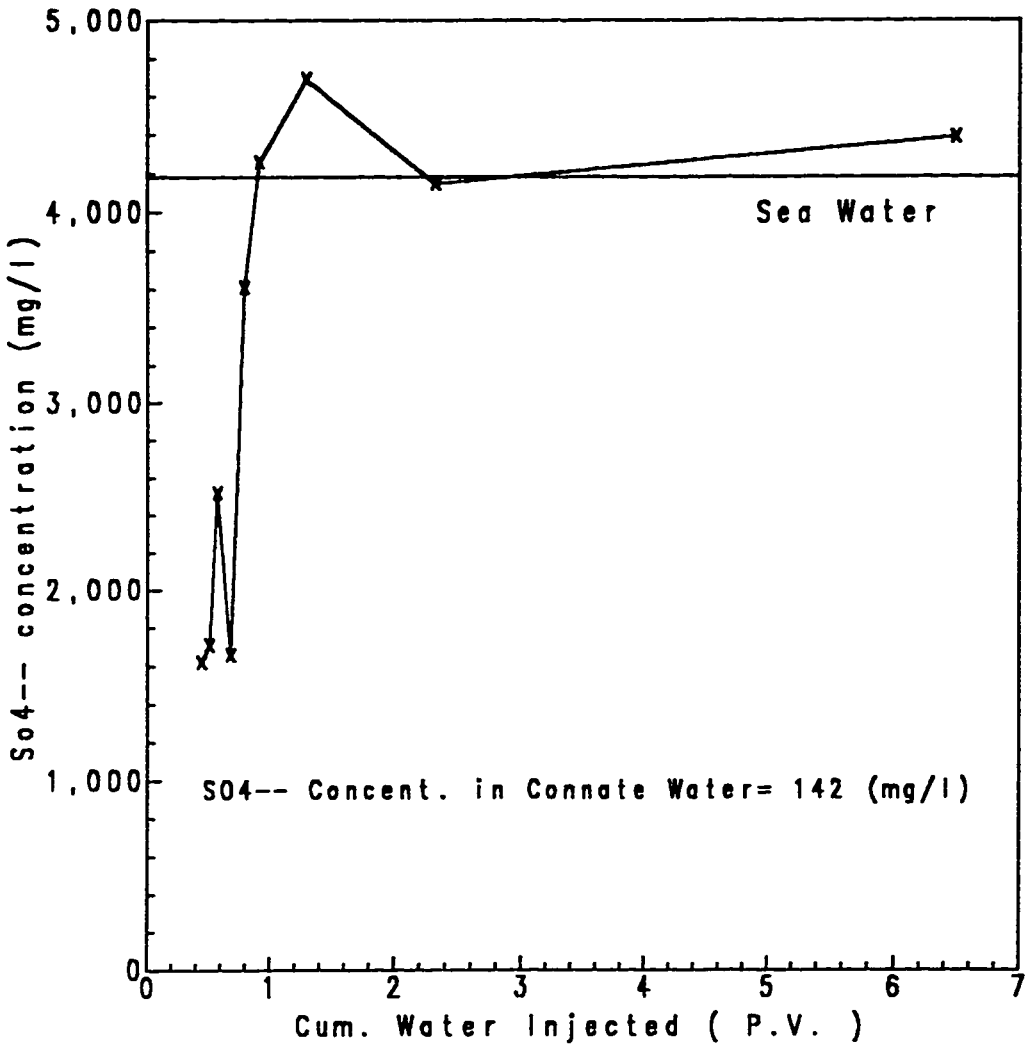


Fig. 4.55 - SO4-- Concentration vs. Cum. Water Injected for Run#R-7

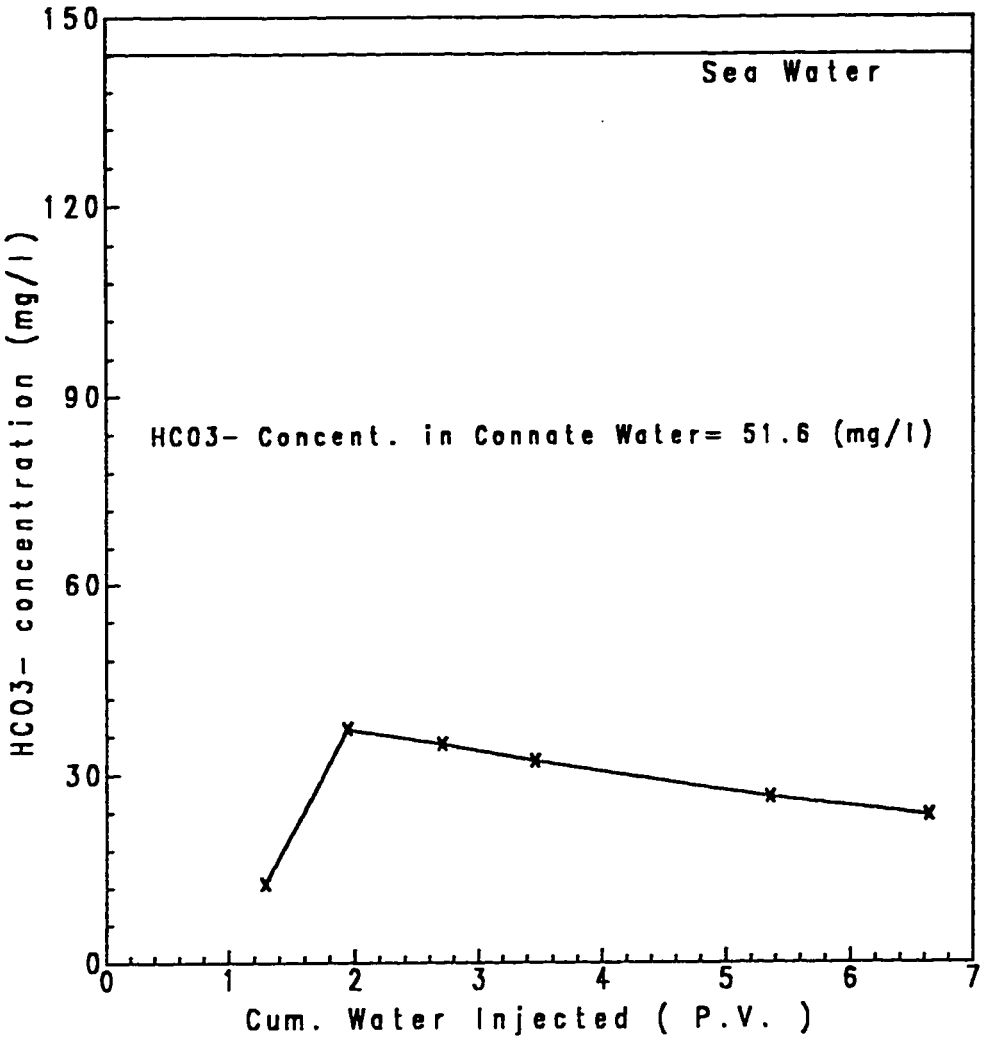


Fig. 4.56 - HCO3- Concentration vs. Cum. Water Injected for Run#R-7

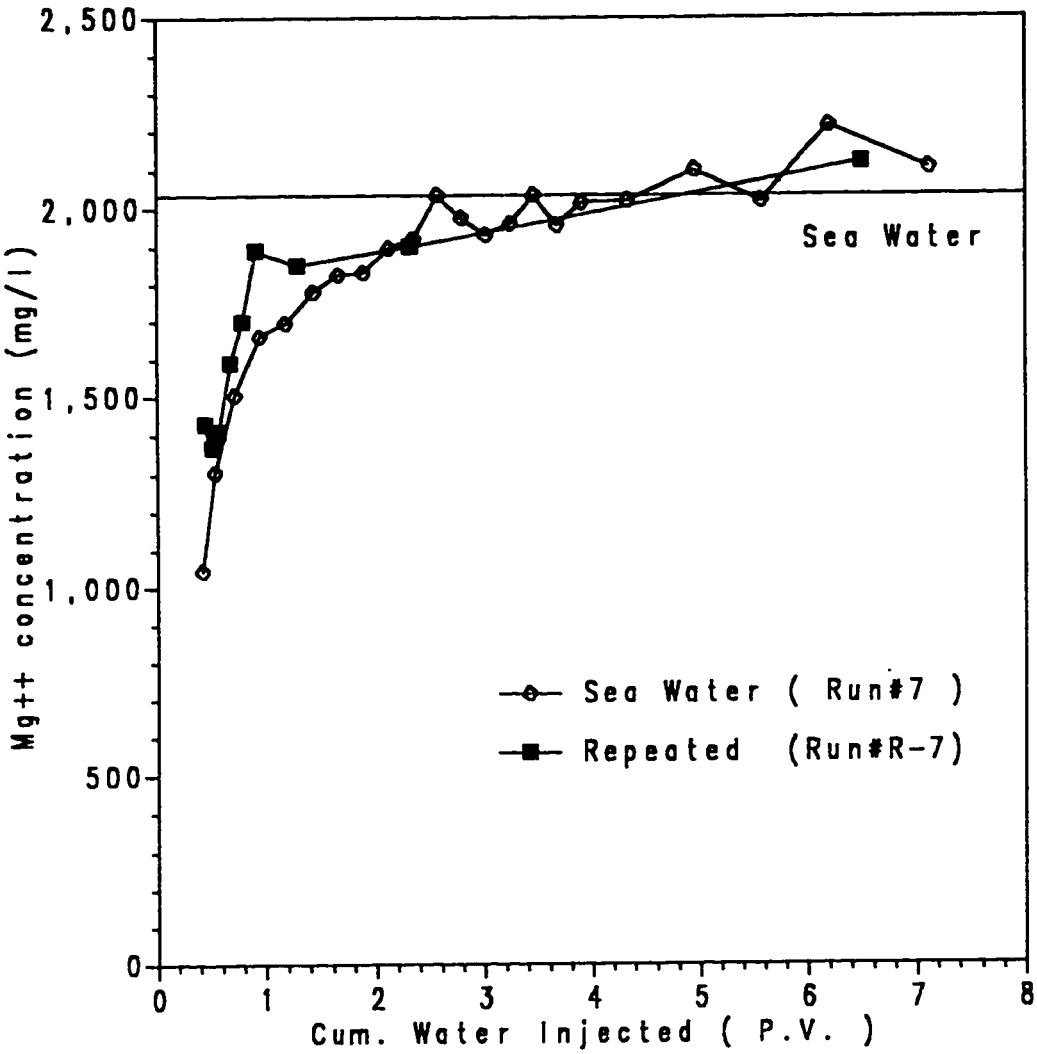


Fig. 4.57 - Mg++ Concentration vs. Cum. Water Injected for Run#7 and Run#R-7

CaO and $CO_2$.

$$CaCO_3 \rightarrow CaO + CO_2$$

When the cores were flooded with waters that contain $Mg^{++}$, the following reactions might happen.

$$CaO + H_2O \rightarrow Ca(OH)_2$$

$$Ca(OH)_2 + Mg^{++} \rightarrow Ca^{++} + Mg(OH)_2$$

which causes the loss of $Mg^{++}$ at the start of the flood.

The low concentration of $HCO_3^-$ in the produced water is believed to be caused by precipitation due to time factor, since the samples waited for 6 weeks before being analyzed. The constant concentration of $HCO_3^-$ is due to the combination of several tubes for one point in the graph. The combination was done because a minimum of 10 ml was required for $HCO_3^-$ determination by titration method.

In summary, no incompatibility problems due to mixing of actual waters with connate Arab-D water could be confirmed from the flooding experiments. This is probably due to the small volume of connate water (5.0 ml), and the occurrence of first contact phenomena. In the

literature, some investigators [14,16] found similar results as was discussed in the literature review.

# CHAPTER 5

# Chapter 5

## SUMMARY, CONCLUSIONS, AND RECOMMENDATIONS

### 5.1 SUMMARY

1. An Experimental investigation of the effect of injected water Salinity on oil recovery was conducted.
2. Experiments were conducted at a temperature of 90°C. and a net overburden pressure of 1500 psi.
3. Fired Berea sandstone core samples were used as the consolidated porous medium.
4. Arabian Light crude oil was used as the oleic phase. Different concentrations of NaCl brines , sea water, Wasia water, and 100,000 (mg/l) synthetic Arab-D water were used for injection purposes.
5. 20 % NaCl brine was used as connate water in the NaCl brines runs, while synthetic formation Arab-D water was used for actual water runs.

### 5.2 CONCLUSIONS

1. Oil recovery increased as the injected water salinity increased up to 10 % for NaCl brine Runs. Increasing the injected water salinity beyond 10 % did not give a significant increase in oil recovery.

2. The difference in oil recovery among actual water runs was small compared to the difference among the same salinities in the NaCl brine runs.
3. The IFT decreased with increasing water salinity up to 10 % NaCl, where it started to increase slightly beyond this salinity.
4. The relative permeability ratio ( Kro/Krw ) increased as the injected water salinity increased.
5. The compatibility tests showed that when connate Arab-D water was mixed with sea water at reservoir temperature, calcium sulphate precipitated.
6. Analysis of the coreflooding effluents did not show any incompatibility problems due to injection of Wasia , sea, and 100,000 (mg/l) Arab-D waters .

## 5.3 RECOMMENDATIONS

The effect of injected water salinity on oil recovery under different injection rates using actual limestone core samples should be investigated.

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## REFERENCES


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# APPENDICES

# APPENDIX A

## Raw Data

**Table - A.1**

**Raw Data for Run # 1**

**Pore Volume = 32.64 cc**

**Initial Oil In Place = 27.45 cc**

| Cum. Water Injected | Oil Produced | Pressure Drop | Rate | Produced Water Salinity |
|---|---|---|---|---|
| (cc) | (cc) | (psi) | (cc/hour) | (mg/l) |
| 3.85 | 3.85 | 3.250 | 28.875 | - |
| 7.80 | 7.80 | 3.750 | 29.625 | - |
| 12.00 | 10.00 | 5.000 | 31.500 | 155000 |
| 16.20 | 10.00 | 5.000 | 31.500 | 131000 |
| 20.50 | 10.05 | 4.000 | 32.250 | 108000 |
| 24.70 | 10.05 | 3.900 | 31.500 | 64000 |
| 29.70 | 10.13 | 3.250 | 37.500 | 28000 |
| 33.90 | 10.18 | 5.250 | 31.500 | 22000 |
| 38.10 | 10.20 | 2.500 | 31.500 | 18500 |
| 42.30 | 10.25 | 3.250 | 31.500 | 15500 |
| 46.50 | 10.32 | 3.750 | 31.500 | 12700 |
| 50.70 | 10.37 | 3.500 | 31.500 | 11000 |
| 54.70 | 10.40 | 4.000 | 30.000 | 9000 |
| 58.70 | 10.45 | 3.750 | 30.000 | 9500 |
| 62.80 | 10.46 | 3.750 | 30.750 | 8000 |
| 67.40 | 10.51 | 3.750 | 34.500 | 7800 |
| 69.90 | 10.52 | 4.000 | 18.750 | 8200 |
| 73.40 | 10.53 | 2.000 | 26.250 | 8200 |
| 77.35 | 10.55 | 3.000 | 29.625 | 6800 |
| 81.65 | 10.56 | 3.250 | 32.250 | 7000 |
| 84.65 | 10.56 | 4.000 | 22.500 | 6700 |
| 88.35 | 10.61 | 2.500 | 27.750 | 6500 |
| 91.75 | 10.61 | 3.250 | 25.500 | 7600 |
| 95.65 | 10.64 | 2.600 | 29.250 | 6500 |
| 99.75 | 10.66 | 3.250 | 30.750 | 6500 |
| 103.95 | 10.66 | 3.600 | 31.500 | 6300 |
| 107.65 | 10.66 | 3.500 | 27.750 | 6500 |
| 111.25 | 10.66 | 3.250 | 27.000 | 6500 |
| 115.05 | 10.71 | 3.000 | 28.500 | 6000 |

**Table A.1 (Contd.)**

| Cum. Water Injected | Oil Produced | Pressure Drop | Rate | Produced Water Salinity |
|---|---|---|---|---|
| (cc) | (cc) | (psi) | (cc/hour) | (mg/l) |
| 118.05 | 10.71 | 2.250 | 22.500 | 6000 |
| 121.35 | 10.76 | 2.250 | 24.750 | 5900 |
| 124.75 | 10.76 | 3.750 | 25.500 | 5800 |
| 128.45 | 10.76 | 3.150 | 27.750 | 5600 |
| 132.25 | 10.76 | 3.250 | 28.500 | 5700 |
| 135.25 | 10.76 | 3.250 | 22.500 | 5500 |
| 137.95 | 10.80 | 3.000 | 20.250 | 5600 |
| 141.45 | 10.81 | 2.000 | 26.250 | 5500 |
| 144.95 | 10.81 | 2.250 | 26.250 | 5800 |
| 148.85 | 10.81 | 3.100 | 29.250 | 5700 |
| 152.85 | 10.81 | 3.200 | 30.000 | 5500 |
| 156.65 | 10.81 | 3.200 | 28.500 | 5500 |
| 160.45 | 10.81 | 3.100 | 28.500 | 5500 |
| 163.85 | 10.81 | 2.150 | 25.500 | 5500 |
| 167.45 | 10.85 | 2.250 | 27.000 | 5500 |

**Table - A.2**

**Raw Data for Run # 2**

**Pore Volume = 33.59 cc**

**Initial Oil In Place = 28.47 cc**

| Cum. Water Injected | Oil Produced | Pressure Drop | Rate | Produced Water Salinity |
|---|---|---|---|---|
| (cc) | (cc) | (psi) | (cc/hour) | (mg/l) |
| 3.50 | 3.50 | 2.900 | 26.250 | - |
| 7.40 | 7.40 | 3.200 | 29.250 | - |
| 12.00 | 10.80 | 3.800 | 34.500 | - |
| 16.00 | 10.90 | 4.000 | 30.000 | 165000 |
| 19.90 | 10.90 | 3.800 | 29.250 | 95000 |
| 22.70 | 10.98 | 3.500 | 21.000 | 52000 |
| 26.10 | 11.06 | 3.200 | 25.500 | 33000 |
| 30.10 | 11.36 | 3.200 | 30.000 | 27000 |
| 34.10 | 11.51 | 3.400 | 30.000 | 24500 |
| 38.90 | 11.81 | 3.500 | 36.000 | 23500 |
| 43.00 | 11.91 | 3.400 | 30.750 | 22500 |
| 47.60 | 12.01 | 3.000 | 34.500 | 21000 |
| 51.70 | 12.09 | 3.200 | 30.750 | 19500 |
| 56.20 | 12.19 | 2.500 | 33.750 | 19000 |
| 60.10 | 12.22 | 2.600 | 29.250 | 18700 |
| 64.20 | 12.30 | 2.900 | 30.750 | 18300 |
| 68.50 | 12.40 | 2.500 | 32.250 | 18000 |
| 72.40 | 12.48 | 2.500 | 29.250 | 17700 |
| 76.50 | 12.58 | 2.500 | 30.750 | 17600 |
| 80.90 | 12.63 | 2.600 | 33.000 | 17100 |
| 84.80 | 12.68 | 2.550 | 29.250 | 17000 |
| 88.80 | 12.73 | 2.300 | 30.000 | 17300 |
| 93.10 | 12.82 | 2.550 | 32.250 | 16800 |
| 96.70 | 12.82 | 2.100 | 27.000 | 16500 |
| 101.10 | 12.85 | 2.450 | 33.000 | 15800 |
| 104.90 | 12.90 | 2.300 | 28.500 | 16800 |
| 109.10 | 12.98 | 2.400 | 31.500 | 16000 |
| 113.30 | 13.06 | 2.350 | 31.500 | 17300 |
| 117.40 | 13.06 | 2.200 | 30.750 | 16500 |

**Table - A.2 (Contd.)**

| Cum. Water Injected | Oil Produced | Pressure Drop | Rate | Produced Water Salinity |
|---|---|---|---|---|
| (cc) | (cc) | (psi) | (cc/hour) | (mg/l) |
| 120.90 | 13.08 | 2.000 | 26.250 | 16800 |
| 125.00 | 13.11 | 2.400 | 30.750 | 16400 |
| 129.20 | 13.17 | 2.450 | 31.500 | 16800 |
| 133.20 | 13.19 | 2.350 | 30.000 | 16400 |
| 137.30 | 13.22 | 2.300 | 30.750 | 16000 |
| 141.30 | 13.22 | 2.250 | 30.000 | 16000 |
| 145.50 | 13.30 | 2.350 | 31.500 | 15500 |
| 149.50 | 13.30 | 2.300 | 30.000 | 16000 |
| 153.50 | 13.33 | 2.200 | 30.000 | 15000 |
| 157.50 | 13.35 | 2.200 | 30.000 | 15000 |
| 161.30 | 13.38 | 2.200 | 28.500 | 15400 |
| 165.20 | 13.42 | 2.350 | 29.250 | 15400 |
| 169.20 | 13.48 | 2.300 | 30.000 | 15000 |
| 173.20 | 13.53 | 2.300 | 30.000 | 15200 |
| 177.40 | 13.57 | 2.350 | 31.500 | 15300 |
| 181.50 | 13.57 | 2.300 | 30.750 | 15000 |
| 185.50 | 13.63 | 2.300 | 30.000 | 14900 |
| 189.60 | 13.64 | 2.200 | 30.750 | 15000 |
| 193.60 | 13.69 | 2.250 | 30.000 | 15000 |
| 197.60 | 13.69 | 2.250 | 30.000 | 15000 |
| 201.40 | 13.69 | 2.230 | 28.500 | 15100 |
| 205.40 | 13.69 | 2.300 | 30.000 | 15000 |
| 209.40 | 13.74 | 2.350 | 30.000 | 15000 |
| 213.30 | 13.74 | 2.200 | 29.250 | 15000 |
| 217.20 | 13.74 | 2.300 | 29.250 | 15100 |
| 221.10 | 13.78 | 2.350 | 29.250 | 14900 |
| 225.10 | 13.78 | 2.330 | 30.000 | 15000 |
| 229.10 | 13.78 | 2.300 | 30.000 | 15000 |

**Table - A.3**

**Raw Data for Run # 3**

**Pore Volume = 32.89 cc**

**Initial Oil In Place = 28.13 cc**

| Cum. Water Injected | Oil Produced | Pressure Drop | Rate | Produced Water Salinity |
|---|---|---|---|---|
| (cc) | (cc) | (psi) | (cc/hour) | (mg/l) |
| 3.50 | 3.50 | 2.200 | 26.250 | - |
| 7.16 | 7.16 | 2.550 | 27.450 | - |
| 10.82 | 10.82 | 3.000 | 27.450 | - |
| 14.52 | 11.32 | 3.500 | 27.750 | 132000 |
| 18.52 | 11.34 | 3.200 | 30.000 | 99000 |
| 22.52 | 11.40 | 3.250 | 30.000 | 73000 |
| 26.52 | 11.45 | 3.300 | 30.000 | 50000 |
| 30.52 | 11.52 | 3.250 | 30.000 | 37500 |
| 34.42 | 11.56 | 3.000 | 29.250 | 36000 |
| 38.52 | 11.66 | 3.100 | 30.750 | 34000 |
| 42.52 | 11.81 | 3.000 | 30.000 | 31000 |
| 46.52 | 11.91 | 2.950 | 30.000 | 33000 |
| 50.52 | 11.96 | 2.850 | 30.000 | 30500 |
| 54.62 | 12.11 | 2.800 | 30.750 | 29500 |
| 58.62 | 12.19 | 2.600 | 30.000 | 29700 |
| 62.62 | 12.26 | 2.750 | 30.000 | 29700 |
| 66.62 | 12.31 | 2.500 | 30.000 | 29000 |
| 70.62 | 12.38 | 2.600 | 30.000 | 29300 |
| 74.52 | 12.42 | 2.420 | 29.250 | 29500 |
| 78.42 | 12.52 | 2.200 | 29.250 | 29500 |
| 82.42 | 12.60 | 2.250 | 30.000 | 29000 |
| 86.42 | 12.68 | 2.200 | 30.000 | 29000 |
| 90.32 | 12.74 | 2.250 | 29.250 | 29000 |
| 94.22 | 12.84 | 2.000 | 29.250 | 29200 |
| 98.22 | 12.93 | 2.050 | 30.000 | 29200 |
| 102.22 | 13.00 | 1.860 | 30.000 | 29000 |
| 106.12 | 13.05 | 1.700 | 29.250 | 29000 |
| 110.02 | 13.11 | 1.780 | 29.250 | 29000 |
| 113.92 | 13.19 | 1.750 | 29.250 | 29500 |
| 117.82 | 13.21 | 1.600 | 29.250 | 29500 |

**Table - A.3 (Contd.)**

| Cum. Water Injected | Oil Produced | Pressure Drop | Rate | Produced Water Salinity |
|---|---|---|---|---|
| (cc) | (cc) | (psi) | (cc/hour) | (mg/l) |
| 121.67 | 13.28 | 1.600 | 28.875 | 29400 |
| 125.67 | 13.33 | 1.580 | 30.000 | 30000 |
| 129.57 | 13.38 | 1.500 | 29.250 | 30200 |
| 133.47 | 13.38 | 1.450 | 29.250 | 30000 |
| 137.37 | 13.48 | 1.400 | 29.250 | 30000 |
| 141.27 | 13.48 | 1.400 | 29.250 | 29000 |
| 145.27 | 13.53 | 1.600 | 30.000 | 29000 |
| 149.07 | 13.57 | 1.500 | 28.500 | 29800 |
| 153.07 | 13.57 | 1.420 | 30.000 | 29900 |
| 156.97 | 13.60 | 1.410 | 29.250 | 30000 |
| 160.87 | 13.68 | 1.300 | 29.250 | 29500 |
| 164.87 | 13.74 | 1.440 | 30.000 | 30000 |
| 168.77 | 13.84 | 1.400 | 29.250 | 30000 |
| 172.77 | 13.84 | 1.500 | 30.000 | 30000 |
| 176.67 | 13.88 | 1.380 | 29.250 | 30000 |
| 180.67 | 13.89 | 1.330 | 30.000 | 30000 |
| 184.57 | 13.94 | 1.200 | 29.250 | 30000 |
| 188.57 | 13.94 | 1.280 | 30.000 | 29800 |
| 192.57 | 14.02 | 1.280 | 30.000 | 30000 |
| 196.57 | 14.12 | 1.250 | 30.000 | 29000 |
| 200.47 | 14.13 | 1.230 | 29.250 | 29800 |
| 204.47 | 14.14 | 1.200 | 30.000 | 29900 |
| 208.37 | 14.15 | 1.200 | 29.250 | 30000 |
| 212.37 | 14.25 | 1.200 | 30.000 | 30000 |
| 216.37 | 14.26 | 1.190 | 30.000 | 30000 |
| 220.27 | 14.26 | 1.190 | 29.250 | 29000 |
| 224.17 | 14.32 | 1.180 | 29.250 | 29500 |
| 228.67 | 14.39 | 1.180 | 33.750 | 29500 |
| 232.57 | 14.39 | 1.200 | 29.250 | 29800 |
| 236.57 | 14.39 | 1.200 | 30.000 | 30000 |

**Table - A.4**

**Raw Data for Run # 4**

**Pore Volume = 31.49 cc**

**Initial Oil In Place = 26.58 cc**

| Cum. Water Injected | Oil Produced | Pressure Drop | Rate | Produced Water Salinity |
|---|---|---|---|---|
| (cc) | (cc) | (psi) | (cc/hour) | (mg/l) |
| 0.23 | 0.23 | 3.300 | 30.000 | - |
| 2.23 | 2.23 | 3.350 | 30.000 | - |
| 4.23 | 4.23 | 3.400 | 30.000 | - |
| 6.23 | 6.23 | 3.950 | 30.000 | - |
| 8.23 | 8.23 | 3.950 | 30.000 | - |
| 10.23 | 10.23 | 4.000 | 30.000 | - |
| 12.28 | 12.28 | 4.650 | 30.750 | - |
| 14.28 | 12.78 | 4.650 | 30.000 | - |
| 16.28 | 13.03 | 4.250 | 30.000 | 160000 |
| 18.28 | 13.18 | 4.450 | 30.000 | 130000 |
| 20.28 | 13.33 | 4.450 | 30.000 | 100000 |
| 24.28 | 13.49 | 3.850 | 30.000 | 88000 |
| 28.28 | 13.61 | 4.050 | 30.000 | 75000 |
| 32.58 | 13.71 | 3.750 | 32.250 | 70000 |
| 36.58 | 13.79 | 3.750 | 30.000 | 67000 |
| 40.58 | 13.90 | 3.300 | 30.000 | 64000 |
| 44.73 | 13.96 | 3.550 | 31.125 | 60000 |
| 48.73 | 14.04 | 3.550 | 30.000 | 59000 |
| 52.73 | 14.13 | 3.450 | 30.000 | 61000 |
| 56.73 | 14.17 | 3.550 | 30.000 | 62000 |
| 60.73 | 14.20 | 3.550 | 30.000 | 63000 |
| 64.73 | 14.28 | 3.450 | 30.000 | 60000 |
| 68.73 | 14.29 | 3.400 | 30.000 | 60000 |
| 72.73 | 14.29 | 3.430 | 30.000 | 58000 |
| 76.73 | 14.37 | 3.450 | 30.000 | 59000 |
| 80.73 | 14.37 | 3.450 | 30.000 | 61000 |
| 84.73 | 14.40 | 3.250 | 30.000 | 60000 |
| 88.73 | 14.40 | 3.300 | 30.000 | 61000 |
| 92.73 | 14.40 | 3.350 | 30.000 | 59000 |
| 96.58 | 14.40 | 3.300 | 28.875 | 58000 |

**Table - A.4 (Contd.)**

| Cum. Water Injected | Oil Produced | Pressure Drop | Rate | Produced Water Salinity |
|---|---|---|---|---|
| (cc) | (cc) | (psi) | (cc/hour) | (mg/l) |
| 99.78 | 14.41 | 3.130 | 24.000 | 60000 |
| 103.58 | 14.41 | 2.450 | 28.500 | 60000 |
| 107.48 | 14.41 | 2.970 | 29.250 | 60000 |
| 111.38 | 14.41 | 3.050 | 29.250 | 60000 |
| 115.38 | 14.41 | 3.250 | 30.000 | 60000 |
| 119.38 | 14.49 | 3.250 | 30.000 | 62000 |
| 123.38 | 14.50 | 3.270 | 30.000 | 59000 |
| 127.38 | 14.50 | 3.200 | 30.000 | 59000 |
| 131.38 | 14.50 | 3.230 | 30.000 | 59000 |
| 135.38 | 14.50 | 3.200 | 30.000 | 60000 |
| 139.18 | 14.50 | 3.170 | 28.500 | 61000 |
| 143.08 | 14.51 | 3.050 | 29.250 | 60000 |
| 147.08 | 14.51 | 3.050 | 30.000 | 60000 |
| 151.08 | 14.51 | 3.180 | 30.000 | 60000 |
| 154.98 | 14.51 | 3.150 | 29.250 | 60000 |
| 158.98 | 14.51 | 3.160 | 30.000 | 60000 |
| 162.98 | 14.51 | 3.190 | 30.000 | 60500 |
| 166.93 | 14.51 | 3.200 | 29.625 | 59500 |
| 170.88 | 14.51 | 3.190 | 29.625 | 60000 |
| 174.73 | 14.51 | 3.160 | 28.875 | 60000 |
| 178.63 | 14.51 | 3.050 | 29.250 | 60000 |
| 182.58 | 14.51 | 3.050 | 29.625 | 60000 |
| 186.58 | 14.51 | 3.150 | 30.000 | 59700 |
| 190.58 | 14.51 | 3.150 | 30.000 | 59800 |
| 194.58 | 14.51 | 3.150 | 30.000 | 60000 |
| 198.58 | 14.51 | 3.170 | 30.000 | 60000 |
| 202.48 | 14.51 | 3.190 | 29.250 | 59000 |
| 206.28 | 14.51 | 3.200 | 28.500 | 60500 |
| 209.48 | 14.51 | 2.400 | 24.000 | 60500 |
| 213.18 | 14.51 | 2.950 | 27.750 | 59500 |
| 217.03 | 14.51 | 3.100 | 28.875 | 60000 |
| 220.93 | 14.51 | 3.250 | 29.250 | 60000 |
| 224.83 | 14.51 | 3.250 | 29.250 | 59600 |
| 228.73 | 14.51 | 3.270 | 29.250 | 60000 |
| 232.63 | 14.51 | 3.250 | 29.250 | 60000 |
| 236.53 | 14.51 | 2.750 | 29.250 | 60000 |

**Table - A.5**

**Raw Data for Run # 5**

**Pore Volume = 31.1 cc**

**Initial Oil In Place = 26.34 cc**

| Cum. Water Injected | Oil Produced | Pressure Drop | Rate | Produced Water Salinity |
|---|---|---|---|---|
| (cc) | (cc) | (psi) | (cc/hour) | (mg/l) |
| 0.40 | 0.40 | 2.980 | 30.000 | - |
| 2.45 | 2.45 | 3.170 | 30.750 | - |
| 4.52 | 4.52 | 3.450 | 31.050 | - |
| 6.52 | 6.52 | 3.250 | 30.000 | - |
| 8.59 | 8.59 | 3.200 | 31.050 | - |
| 10.69 | 10.69 | 3.100 | 31.500 | - |
| 12.69 | 12.69 | 3.050 | 30.000 | - |
| 14.69 | 12.94 | 3.150 | 30.000 | 170000 |
| 16.69 | 13.14 | 2.950 | 30.000 | 150000 |
| 18.69 | 13.29 | 2.850 | 30.000 | 130000 |
| 20.77 | 13.39 | 2.750 | 31.200 | 125000 |
| 24.67 | 13.61 | 2.650 | 29.250 | 115000 |
| 28.67 | 13.76 | 2.850 | 30.000 | 108000 |
| 32.67 | 13.86 | 2.800 | 30.000 | 102000 |
| 36.67 | 13.97 | 2.800 | 30.000 | 100000 |
| 40.77 | 14.07 | 2.750 | 30.750 | 100000 |
| 44.82 | 14.18 | 2.750 | 30.375 | 100000 |
| 48.92 | 14.28 | 2.800 | 30.750 | 99000 |
| 52.92 | 14.36 | 2.600 | 30.000 | 98000 |
| 56.92 | 14.46 | 2.600 | 30.000 | 101000 |
| 60.92 | 14.53 | 2.450 | 30.000 | 100000 |
| 64.92 | 14.63 | 2.550 | 30.000 | 100000 |
| 68.92 | 14.73 | 2.350 | 30.000 | 100000 |
| 72.92 | 14.78 | 2.400 | 30.000 | 100000 |
| 76.92 | 14.87 | 2.450 | 30.000 | 99000 |
| 80.92 | 14.89 | 2.250 | 30.000 | 97000 |
| 84.92 | 14.96 | 2.300 | 30.000 | 101000 |
| 88.82 | 14.99 | 2.250 | 29.250 | 100000 |
| 92.77 | 15.08 | 2.250 | 29.625 | 100000 |
| 96.67 | 15.08 | 2.200 | 29.250 | 100000 |

**Table - A.5 (Contd.)**

| Cum. Water Injected | Oil Produced | Pressure Drop | Rate | Produced Water Salinity |
|---|---|---|---|---|
| (cc) | (cc) | (psi) | (cc/hour) | (mg/l) |
| 100.62 | 15.14 | 2.150 | 29.625 | 100000 |
| 104.57 | 15.19 | 2.250 | 29.625 | 102000 |
| 108.57 | 15.25 | 2.150 | 30.000 | 101000 |
| 112.57 | 15.28 | 2.100 | 30.000 | 100000 |
| 116.57 | 15.29 | 2.150 | 30.000 | 100000 |
| 120.17 | 15.30 | 2.150 | 27.000 | 99900 |
| 124.02 | 15.36 | 2.100 | 28.875 | 100000 |
| 127.97 | 15.37 | 2.200 | 29.625 | 101000 |
| 131.87 | 15.37 | 2.200 | 29.250 | 102000 |
| 135.87 | 15.38 | 2.150 | 30.000 | 100000 |
| 139.57 | 15.38 | 2.000 | 27.750 | 98000 |
| 143.47 | 15.38 | 2.200 | 29.250 | 99000 |
| 147.37 | 15.38 | 2.300 | 29.250 | 100000 |
| 151.37 | 15.40 | 2.250 | 30.000 | 101000 |
| 155.27 | 15.40 | 2.350 | 29.250 | 100000 |
| 159.17 | 15.40 | 2.000 | 29.250 | 100000 |
| 162.97 | 15.41 | 2.150 | 28.500 | 100000 |
| 166.87 | 15.41 | 2.200 | 29.250 | 100000 |
| 170.87 | 15.41 | 2.200 | 30.000 | 100000 |
| 174.82 | 15.41 | 2.200 | 29.625 | 101000 |
| 178.62 | 15.42 | 2.050 | 28.500 | 102000 |
| 182.52 | 15.42 | 2.150 | 29.250 | 100000 |
| 186.52 | 15.42 | 2.250 | 30.000 | 100000 |
| 190.52 | 15.42 | 2.250 | 30.000 | 100000 |
| 194.32 | 15.42 | 2.350 | 28.500 | 100000 |
| 198.22 | 15.45 | 2.000 | 29.250 | 99000 |
| 202.12 | 15.45 | 2.150 | 29.250 | 101000 |
| 206.12 | 15.46 | 2.250 | 30.000 | 103000 |
| 209.92 | 15.46 | 2.100 | 28.500 | 98000 |
| 213.82 | 15.46 | 2.050 | 29.250 | 100000 |
| 217.72 | 15.46 | 2.250 | 29.250 | 100000 |
| 221.72 | 15.47 | 2.200 | 30.000 | 100000 |
| 225.62 | 15.47 | 2.200 | 29.250 | 100000 |
| 229.12 | 15.48 | 2.200 | 26.250 | 100000 |
| 232.12 | 15.48 | 1.600 | 22.500 | 100000 |
| 236.02 | 15.48 | 2.100 | 29.250 | 99000 |
| 239.92 | 15.48 | 2.200 | 29.250 | 99000 |

**Table - A.6**

**Raw Data for Run # 6**

**Pore Volume = 31.95 cc**

**Initial Oil In Place = 26.93 cc**

| Cum. Water Injected | Oil Produced | Pressure Drop | Rate | Produced Water Salinity |
|---|---|---|---|---|
| (cc) | (cc) | (psi) | (cc/hour) | (mg/l) |
| 0.98 | 0.98 | 5.200 | 30.154 | - |
| 3.15 | 3.15 | 5.600 | 32.550 | - |
| 5.29 | 5.29 | 6.000 | 32.100 | - |
| 7.42 | 7.42 | 6.150 | 31.950 | - |
| 9.58 | 9.58 | 6.400 | 32.400 | - |
| 11.68 | 11.68 | 6.700 | 31.500 | - |
| 13.88 | 13.68 | 6.200 | 33.000 | - |
| 15.68 | 13.77 | 4.400 | 27.000 | 200000 |
| 17.68 | 13.82 | 4.800 | 30.000 | 200000 |
| 19.58 | 13.84 | 5.000 | 28.500 | 195000 |
| 21.58 | 13.92 | 5.000 | 30.000 | 200000 |
| 23.58 | 14.02 | 4.900 | 30.000 | 196000 |
| 27.48 | 14.12 | 4.300 | 29.250 | 203000 |
| 31.48 | 14.22 | 5.000 | 30.000 | 200000 |
| 35.28 | 14.32 | 4.000 | 28.500 | 200000 |
| 39.28 | 14.42 | 4.300 | 30.000 | 198000 |
| 43.08 | 14.50 | 4.100 | 28.500 | 197000 |
| 46.98 | 14.60 | 3.600 | 29.250 | 202000 |
| 50.88 | 14.68 | 3.900 | 29.250 | 200000 |
| 54.73 | 14.76 | 3.400 | 28.875 | 200000 |
| 58.73 | 14.84 | 3.900 | 30.000 | 200000 |
| 62.53 | 14.94 | 3.600 | 28.500 | 200000 |
| 66.53 | 15.03 | 3.500 | 30.000 | 197000 |
| 70.48 | 15.14 | 3.600 | 29.625 | 201000 |
| 74.48 | 15.16 | 3.700 | 30.000 | 200000 |
| 78.38 | 15.26 | 3.300 | 29.250 | 200000 |
| 81.48 | 15.26 | 3.000 | 23.250 | 200000 |
| 85.53 | 15.38 | 3.600 | 30.375 | 193000 |
| 89.48 | 15.41 | 3.600 | 29.625 | 203000 |
| 93.38 | 15.46 | 3.400 | 29.250 | 200000 |
| 97.28 | 15.51 | 3.400 | 29.250 | 200000 |

**Table - A.6 (Contd.)**

| Cum. Water Injected | Oil Produced | Pressure Drop | Rate | Produced Water Salinity |
|---|---|---|---|---|
| (cc) | (cc) | (psi) | (cc/hour) | (mg/l) |
| 99.78 | 15.51 | 2.600 | 18.750 | 200000 |
| 102.78 | 15.55 | 2.700 | 22.500 | 200000 |
| 106.58 | 15.57 | 3.000 | 28.500 | 200000 |
| 110.38 | 15.57 | 3.300 | 28.500 | 200000 |
| 113.88 | 15.74 | 2.900 | 26.250 | 200000 |
| 117.38 | 15.80 | 2.900 | 26.250 | 200000 |
| 120.88 | 15.83 | 3.000 | 26.250 | 198000 |
| 124.08 | 15.84 | 2.700 | 24.000 | 200000 |
| 127.88 | 15.84 | 3.200 | 28.500 | 200000 |
| 131.68 | 15.84 | 3.100 | 28.500 | 197000 |
| 135.28 | 15.88 | 3.000 | 27.000 | 205000 |
| 139.18 | 15.88 | 3.200 | 29.250 | 200000 |
| 142.58 | 15.88 | 2.900 | 25.500 | 200000 |
| 145.98 | 15.92 | 2.950 | 25.500 | 200000 |
| 149.78 | 16.00 | 3.100 | 28.500 | 198000 |
| 153.28 | 16.00 | 2.800 | 26.250 | 196000 |
| 156.98 | 16.10 | 2.900 | 27.750 | 200000 |
| 160.48 | 16.10 | 2.900 | 26.250 | 202000 |
| 163.68 | 16.15 | 2.700 | 24.000 | 200000 |
| 166.88 | 16.16 | 2.900 | 24.000 | 200000 |
| 169.98 | 16.16 | 2.700 | 23.250 | 200000 |
| 172.78 | 16.16 | 2.900 | 21.000 | 200000 |
| 175.88 | 16.20 | 2.700 | 23.250 | 200000 |
| 179.08 | 16.22 | 2.500 | 24.000 | 195000 |
| 182.28 | 16.27 | 2.600 | 24.000 | 200000 |
| 185.28 | 16.27 | 2.700 | 22.500 | 200000 |
| 188.18 | 16.27 | 2.600 | 21.750 | 200000 |
| 191.08 | 16.30 | 2.500 | 21.750 | 200000 |
| 194.08 | 16.31 | 2.500 | 22.500 | 198000 |
| 197.08 | 16.31 | 2.300 | 22.500 | 200000 |
| 199.58 | 16.31 | 2.400 | 18.750 | 200000 |
| 202.28 | 16.31 | 2.600 | 20.250 | 200000 |
| 205.38 | 16.34 | 2.100 | 23.250 | 196000 |
| 208.38 | 16.36 | 2.200 | 22.500 | 200000 |
| 210.88 | 16.36 | 2.450 | 18.750 | 200000 |
| 213.68 | 16.36 | 2.500 | 21.000 | 200000 |
| 216.58 | 16.36 | 2.250 | 21.750 | 200000 |
| 218.98 | 16.36 | 2.200 | 18.000 | 200000 |

**Table - A.7**

**Raw Data for Run # 7**

**Pore Volume = 35.08 cc**

**Initial Oil In Place = 30.26 cc**

| Cum. Water Injected | Oil Produced | Pressure Drop | Rate |
|---|---|---|---|
| (cc) | (cc) | (psi) | (cc/min) |
| 1.66 | 1.66 | 3.200 | 41.500 |
| 3.76 | 3.76 | 3.400 | 31.500 |
| 5.91 | 5.91 | 3.800 | 32.250 |
| 8.08 | 8.08 | 4.400 | 32.550 |
| 10.28 | 10.28 | 4.750 | 33.000 |
| 12.47 | 12.47 | 4.950 | 32.850 |
| 14.47 | 12.67 | 4.500 | 30.000 |
| 16.52 | 12.80 | 3.900 | 30.750 |
| 18.62 | 12.88 | 3.700 | 31.500 |
| 20.82 | 12.97 | 3.600 | 33.000 |
| 25.12 | 13.12 | 3.700 | 32.250 |
| 29.17 | 13.14 | 3.400 | 30.375 |
| 33.17 | 13.26 | 2.950 | 30.000 |
| 37.17 | 13.36 | 2.750 | 30.000 |
| 41.27 | 13.46 | 2.800 | 30.750 |
| 45.42 | 13.57 | 2.700 | 31.125 |
| 50.12 | 13.66 | 2.800 | 35.250 |
| 54.12 | 13.74 | 2.950 | 30.000 |
| 58.02 | 13.89 | 2.500 | 29.250 |
| 62.02 | 13.95 | 2.300 | 30.000 |
| 66.07 | 14.05 | 2.450 | 30.375 |
| 70.17 | 14.14 | 2.550 | 30.750 |
| 74.27 | 14.21 | 2.450 | 30.750 |
| 78.27 | 14.25 | 2.450 | 30.000 |
| 82.22 | 14.32 | 2.350 | 29.625 |
| 86.12 | 14.40 | 2.200 | 29.250 |
| 89.92 | 14.43 | 2.200 | 28.500 |
| 94.02 | 14.52 | 2.150 | 30.750 |
| 97.82 | 14.58 | 2.300 | 28.500 |

**Table - A.7 (Contd.)**

| Cum. Water Injected | Oil Produced | Pressure Drop | Rate |
|---|---|---|---|
| (cc) | (cc) | (psi) | (cc/min) |
| 101.82 | 14.63 | 2.150 | 30.000 |
| 105.72 | 14.71 | 2.100 | 29.250 |
| 109.72 | 14.80 | 2.050 | 30.000 |
| 113.62 | 14.84 | 2.050 | 29.250 |
| 117.12 | 14.88 | 2.050 | 26.250 |
| 121.02 | 14.93 | 1.590 | 29.250 |
| 125.02 | 14.99 | 2.050 | 30.000 |
| 128.77 | 15.07 | 2.100 | 28.125 |
| 132.67 | 15.11 | 2.000 | 29.250 |
| 136.67 | 15.14 | 2.100 | 30.000 |
| 140.72 | 15.20 | 2.150 | 30.375 |
| 144.22 | 15.22 | 1.800 | 26.250 |
| 148.02 | 15.24 | 1.950 | 28.500 |
| 151.87 | 15.27 | 2.050 | 28.875 |
| 155.57 | 15.30 | 1.900 | 27.750 |
| 159.57 | 15.35 | 1.900 | 30.000 |
| 163.57 | 15.36 | 2.000 | 30.000 |
| 167.57 | 15.40 | 2.050 | 30.000 |
| 170.57 | 15.48 | 2.000 | 22.500 |
| 173.57 | 15.52 | 1.550 | 22.500 |
| 177.57 | 15.52 | 1.750 | 30.000 |
| 181.72 | 15.59 | 2.000 | 31.125 |
| 184.52 | 15.63 | 1.980 | 21.000 |
| 188.12 | 15.67 | 1.500 | 27.000 |
| 191.62 | 15.67 | 1.800 | 26.250 |
| 195.42 | 15.73 | 1.750 | 28.500 |
| 199.02 | 15.74 | 1.880 | 27.000 |
| 202.72 | 15.77 | 1.780 | 27.750 |
| 206.72 | 15.78 | 1.850 | 30.000 |
| 209.72 | 15.80 | 2.000 | 22.500 |
| 213.52 | 15.85 | 1.650 | 28.500 |
| 217.32 | 15.86 | 1.800 | 28.500 |
| 221.12 | 15.87 | 1.850 | 28.500 |
| 224.12 | 15.91 | 1.820 | 22.500 |
| 227.92 | 15.95 | 1.650 | 28.500 |
| 231.52 | 15.95 | 1.800 | 27.000 |
| 235.52 | 15.97 | 1.800 | 30.000 |
| 239.12 | 15.99 | 2.050 | 27.000 |
| 242.22 | 15.99 | 1.700 | 23.250 |
| 245.82 | 15.99 | 1.700 | 27.000 |
| 249.62 | 15.99 | 1.800 | 28.500 |

**Table - A.8**

**Raw Data for Run # 8**

**Pore Volume = 36.84 cc**

**Initial Oil In Place = 31.84 cc**

| Cum. Water Injected | Oil Produced | Pressure Drop | Rate |
|---|---|---|---|
| (cc) | (cc) | (psi) | (cc/min) |
| 0.05 | 0.05 | 2.900 | 30.000 |
| 1.95 | 1.95 | 3.250 | 28.500 |
| 4.00 | 4.00 | 3.480 | 30.750 |
| 6.10 | 6.10 | 3.600 | 31.500 |
| 8.20 | 8.20 | 3.700 | 31.500 |
| 10.32 | 10.32 | 3.820 | 31.800 |
| 12.62 | 12.62 | 3.550 | 34.500 |
| 14.72 | 13.42 | 3.150 | 31.500 |
| 16.72 | 13.54 | 2.850 | 30.000 |
| 18.72 | 13.64 | 2.650 | 30.000 |
| 22.72 | 13.80 | 2.500 | 30.000 |
| 26.82 | 13.90 | 2.400 | 30.750 |
| 30.82 | 14.00 | 2.350 | 30.000 |
| 35.02 | 14.10 | 2.150 | 31.500 |
| 39.22 | 14.20 | 2.300 | 31.500 |
| 43.32 | 14.29 | 2.100 | 30.750 |
| 47.32 | 14.35 | 2.000 | 30.000 |
| 51.32 | 14.43 | 1.900 | 30.000 |
| 55.32 | 14.51 | 1.900 | 30.000 |
| 59.32 | 14.57 | 2.000 | 30.000 |
| 63.32 | 14.65 | 1.950 | 30.000 |
| 67.22 | 14.72 | 1.800 | 29.250 |
| 71.22 | 14.81 | 1.850 | 30.000 |
| 75.22 | 14.86 | 1.870 | 30.000 |
| 79.22 | 14.92 | 1.900 | 30.000 |
| 83.12 | 14.92 | 1.750 | 29.250 |
| 87.12 | 14.97 | 1.750 | 30.000 |
| 91.12 | 15.03 | 1.800 | 30.000 |
| 95.02 | 15.09 | 1.600 | 29.250 |
| 98.42 | 15.16 | 1.450 | 25.500 |

**Table - A.8 (Contd.)**

| Cum. Water Injected | Oil Produced | Pressure Drop | Rate |
|---|---|---|---|
| (cc) | (cc) | (psi) | (cc/min) |
| 101.62 | 15.21 | 1.250 | 24.000 |
| 104.92 | 15.21 | 1.400 | 24.750 |
| 108.72 | 15.29 | 1.550 | 28.500 |
| 112.72 | 15.35 | 1.650 | 30.000 |
| 116.92 | 15.39 | 1.600 | 31.500 |
| 120.92 | 15.45 | 1.600 | 30.000 |
| 124.82 | 15.47 | 1.600 | 29.250 |
| 128.82 | 15.48 | 1.600 | 30.000 |
| 132.82 | 15.54 | 1.650 | 30.000 |
| 136.77 | 15.55 | 1.600 | 29.625 |
| 140.67 | 15.60 | 1.650 | 29.250 |
| 144.67 | 15.63 | 1.600 | 30.000 |
| 148.47 | 15.65 | 1.580 | 28.500 |
| 152.27 | 15.69 | 1.500 | 28.500 |
| 155.97 | 15.74 | 1.450 | 27.750 |
| 158.47 | 15.76 | 1.100 | 18.750 |
| 161.47 | 15.77 | 1.200 | 22.500 |
| 164.87 | 15.79 | 1.320 | 25.500 |
| 168.57 | 15.80 | 1.500 | 27.750 |
| 172.57 | 15.83 | 1.500 | 30.000 |
| 176.57 | 15.83 | 1.550 | 30.000 |
| 180.57 | 15.85 | 1.500 | 30.000 |
| 184.57 | 15.87 | 1.500 | 30.000 |
| 188.47 | 15.89 | 1.450 | 29.250 |
| 192.47 | 15.94 | 1.520 | 30.000 |
| 196.47 | 15.94 | 1.520 | 30.000 |
| 200.47 | 15.94 | 1.510 | 30.000 |
| 204.37 | 16.00 | 1.430 | 29.250 |
| 208.27 | 16.00 | 1.450 | 29.250 |
| 212.27 | 16.03 | 1.520 | 30.000 |
| 216.27 | 16.03 | 1.500 | 30.000 |
| 220.27 | 16.05 | 1.510 | 30.000 |
| 224.27 | 16.05 | 1.500 | 30.000 |
| 228.27 | 16.06 | 1.500 | 30.000 |
| 232.27 | 16.06 | 1.500 | 30.000 |

**Table - A.9**

**Raw Data for Run # 9**

**Pore Volume = 33.24 cc**

**Initial Oil In Place = 28.42 cc**

| Cum. Water Injected | Oil Produced | Pressure Drop | Rate |
|---|---|---|---|
| (cc) | (cc) | (psi) | (cc/min) |
| 0.45 | 0.45 | 3.000 | 29.670 |
| 2.45 | 2.45 | 3.420 | 30.000 |
| 4.45 | 4.45 | 3.700 | 30.000 |
| 6.45 | 6.45 | 3.250 | 30.000 |
| 8.51 | 8.51 | 3.600 | 30.900 |
| 10.56 | 10.56 | 3.600 | 30.750 |
| 12.56 | 12.56 | 3.800 | 30.000 |
| 14.56 | 12.76 | 3.600 | 30.000 |
| 16.56 | 12.84 | 3.500 | 30.000 |
| 20.66 | 12.99 | 3.400 | 30.750 |
| 24.66 | 13.09 | 3.300 | 30.000 |
| 28.76 | 13.19 | 3.120 | 30.750 |
| 32.76 | 13.27 | 3.100 | 30.000 |
| 37.16 | 13.35 | 3.200 | 33.000 |
| 41.16 | 13.42 | 2.900 | 30.000 |
| 45.16 | 13.47 | 2.700 | 30.000 |
| 49.26 | 13.54 | 2.700 | 30.750 |
| 53.26 | 13.63 | 2.820 | 30.000 |
| 57.26 | 13.71 | 2.810 | 30.000 |
| 61.26 | 13.79 | 2.700 | 30.000 |
| 65.26 | 13.87 | 2.650 | 30.000 |
| 69.26 | 13.95 | 2.600 | 30.000 |
| 73.26 | 14.02 | 2.550 | 30.000 |
| 77.26 | 14.10 | 2.630 | 30.000 |
| 82.16 | 14.17 | 2.600 | 36.750 |
| 86.16 | 14.23 | 2.200 | 30.000 |
| 90.16 | 14.30 | 2.350 | 30.000 |
| 94.16 | 14.37 | 2.400 | 30.000 |
| 97.86 | 14.43 | 2.250 | 27.750 |
| 101.66 | 14.51 | 2.000 | 28.500 |
| 105.56 | 14.57 | 2.020 | 29.250 |
| 109.71 | 14.63 | 2.180 | 31.125 |
| 113.71 | 14.68 | 2.200 | 30.000 |
| 117.71 | 14.73 | 2.200 | 30.000 |

**Table - A.9 (Contd.)**

| Cum. Water Injected | Oil Produced | Pressure Drop | Rate |
|---|---|---|---|
| (cc) | (cc) | (psi) | (cc/min) |
| 121.71 | 14.79 | 2.200 | 30.000 |
| 125.71 | 14.84 | 2.180 | 30.000 |
| 129.71 | 14.90 | 2.170 | 30.000 |
| 133.71 | 14.95 | 2.200 | 30.000 |
| 137.71 | 14.99 | 2.120 | 30.000 |
| 141.71 | 15.04 | 2.100 | 30.000 |
| 145.71 | 15.09 | 2.220 | 30.000 |
| 149.71 | 15.14 | 2.210 | 30.000 |
| 153.71 | 15.16 | 2.200 | 30.000 |
| 157.71 | 15.21 | 2.190 | 30.000 |
| 161.71 | 15.25 | 2.180 | 30.000 |
| 165.61 | 15.27 | 2.200 | 29.250 |
| 169.61 | 15.32 | 2.100 | 30.000 |
| 173.61 | 15.35 | 2.150 | 30.000 |
| 177.61 | 15.36 | 2.180 | 30.000 |
| 181.61 | 15.37 | 2.100 | 30.000 |
| 185.61 | 15.38 | 2.070 | 30.000 |
| 189.61 | 15.41 | 2.100 | 30.000 |
| 193.61 | 15.41 | 2.080 | 30.000 |
| 197.61 | 15.41 | 2.100 | 30.000 |
| 201.61 | 15.41 | 2.100 | 30.000 |
| 205.61 | 15.42 | 2.150 | 30.000 |
| 209.51 | 15.43 | 2.000 | 29.250 |
| 213.51 | 15.43 | 2.000 | 30.000 |
| 217.51 | 15.44 | 2.060 | 30.000 |
| 221.51 | 15.45 | 2.010 | 30.000 |
| 225.51 | 15.45 | 2.000 | 30.000 |
| 229.51 | 15.46 | 2.050 | 30.000 |
| 233.51 | 15.46 | 2.000 | 30.000 |
| 237.51 | 15.46 | 2.020 | 30.000 |
| 241.51 | 15.46 | 2.100 | 30.000 |

## Table - A.10

## Raw Data for Run # R-6

## Pore Volume = 31.05 cc

## Initial Oil In Place = 26.67 cc

| Cum. Water Injected | Oil Produced | Pressure Drop | Rate |
|---|---|---|---|
| (cc) | (cc) | (psi) | (cc/min) |
| 1.80 | 1.80 | 3.160 | 30.000 |
| 3.96 | 3.96 | 3.860 | 32.400 |
| 6.13 | 6.13 | 4.460 | 32.550 |
| 8.38 | 8.38 | 4.960 | 33.750 |
| 10.60 | 10.60 | 5.210 | 33.300 |
| 12.70 | 12.70 | 5.760 | 31.500 |
| 14.70 | 12.85 | 5.660 | 30.000 |
| 17.10 | 13.15 | 5.660 | 36.000 |
| 18.90 | 13.23 | 4.660 | 27.000 |
| 23.10 | 13.33 | 5.660 | 31.500 |
| 27.32 | 13.48 | 4.660 | 31.650 |
| 31.54 | 13.68 | 4.960 | 31.650 |
| 35.64 | 13.80 | 4.660 | 30.750 |
| 39.84 | 13.88 | 4.660 | 31.500 |
| 43.99 | 13.99 | 4.160 | 31.125 |
| 48.14 | 14.07 | 4.160 | 31.125 |
| 52.54 | 14.17 | 3.960 | 33.000 |
| 56.94 | 14.23 | 3.860 | 33.000 |
| 60.94 | 14.33 | 3.660 | 30.000 |
| 64.94 | 14.40 | 3.610 | 30.000 |
| 68.99 | 14.50 | 3.360 | 30.375 |
| 73.09 | 14.60 | 3.310 | 30.750 |
| 77.09 | 14.69 | 3.260 | 30.000 |
| 81.24 | 14.78 | 3.260 | 31.125 |
| 85.24 | 14.87 | 3.160 | 30.000 |
| 89.29 | 14.96 | 3.010 | 30.375 |
| 93.29 | 15.04 | 3.060 | 30.000 |
| 97.29 | 15.13 | 2.960 | 30.000 |
| 101.29 | 15.17 | 2.940 | 30.000 |
| 105.29 | 15.19 | 2.860 | 30.000 |
| 109.29 | 15.29 | 2.810 | 30.000 |
| 113.34 | 15.38 | 2.810 | 30.375 |
| 117.34 | 15.44 | 2.780 | 30.000 |

## Table - A.10 (Contd.)

| Cum. Water Injected | Oil Produced | Pressure Drop | Rate |
|---|---|---|---|
| (cc) | (cc) | (psi) | (cc/min) |
| 121.34 | 15.45 | 2.710 | 30.000 |
| 125.34 | 15.53 | 2.760 | 30.000 |
| 129.39 | 15.53 | 2.710 | 30.375 |
| 133.39 | 15.61 | 2.660 | 30.000 |
| 137.34 | 15.61 | 2.710 | 29.625 |
| 141.39 | 15.66 | 2.680 | 30.375 |
| 145.39 | 15.72 | 2.660 | 30.000 |
| 149.39 | 15.73 | 2.660 | 30.000 |
| 153.39 | 15.73 | 2.660 | 30.000 |
| 157.34 | 15.75 | 2.610 | 29.625 |
| 161.34 | 15.84 | 2.640 | 30.000 |
| 165.34 | 15.91 | 2.610 | 30.000 |
| 169.34 | 15.92 | 2.560 | 30.000 |
| 173.34 | 15.92 | 2.610 | 30.000 |
| 177.29 | 15.92 | 2.560 | 29.625 |
| 181.29 | 15.99 | 2.560 | 30.000 |
| 185.29 | 16.00 | 2.560 | 30.000 |
| 189.34 | 16.02 | 2.510 | 30.375 |
| 193.24 | 16.03 | 2.510 | 29.250 |
| 197.24 | 16.05 | 2.510 | 30.000 |
| 201.09 | 16.11 | 2.510 | 28.875 |
| 205.09 | 16.11 | 2.500 | 30.000 |
| 209.09 | 16.16 | 2.480 | 30.000 |
| 213.09 | 16.16 | 2.460 | 30.000 |
| 217.09 | 16.16 | 2.460 | 30.000 |

**Table - A.11**

**Raw Data for Run # R-7**

**Pore Volume = 31.54 cc**

**Initial Oil In Place = 26.98 cc**

| Cum. Water Injected | Oil Produced | Pressure Drop | Rate |
|---|---|---|---|
| (cc) | (cc) | (psi) | (cc/min) |
| 0.91 | 0.91 | 2.800 | 30.000 |
| 2.91 | 2.91 | 3.710 | 30.000 |
| 4.91 | 4.91 | 4.100 | 30.000 |
| 6.91 | 6.91 | 4.100 | 30.000 |
| 8.88 | 8.88 | 4.050 | 29.550 |
| 10.43 | 10.43 | 4.050 | 23.250 |
| 11.93 | 11.63 | 4.080 | 22.500 |
| 13.93 | 11.93 | 3.500 | 30.000 |
| 16.03 | 12.33 | 3.000 | 31.500 |
| 18.03 | 12.43 | 3.000 | 30.000 |
| 21.53 | 12.45 | 3.000 | 26.250 |
| 25.03 | 12.45 | 2.800 | 26.250 |
| 28.83 | 12.54 | 3.500 | 28.500 |
| 32.83 | 12.64 | 2.500 | 30.000 |
| 36.83 | 12.74 | 2.500 | 30.000 |
| 40.83 | 12.84 | 2.900 | 30.000 |
| 44.98 | 12.92 | 2.500 | 31.125 |
| 48.98 | 13.00 | 2.400 | 30.000 |
| 52.98 | 13.06 | 2.350 | 30.000 |
| 57.13 | 13.16 | 2.300 | 31.125 |
| 61.28 | 13.24 | 2.250 | 31.125 |
| 65.18 | 13.32 | 2.200 | 29.250 |
| 69.18 | 13.36 | 2.400 | 30.000 |
| 73.23 | 13.45 | 2.000 | 30.375 |
| 77.23 | 13.48 | 2.000 | 30.000 |
| 81.23 | 13.54 | 2.200 | 30.000 |
| 85.13 | 13.59 | 2.000 | 29.250 |
| 89.13 | 13.65 | 2.100 | 30.000 |
| 93.13 | 13.71 | 2.000 | 30.000 |
| 97.13 | 13.79 | 1.900 | 30.000 |
| 101.13 | 13.79 | 1.850 | 30.000 |
| 105.13 | 13.82 | 1.800 | 30.000 |
| 109.13 | 13.89 | 1.800 | 30.000 |

**Table - A.11 (Contd.)**

| Cum. Water Injected | Oil Produced | Pressure Drop | Rate |
|---|---|---|---|
| (cc) | (cc) | (psi) | (cc/min) |
| 113.13 | 13.89 | 1.700 | 30.000 |
| 117.28 | 13.99 | 1.700 | 31.125 |
| 121.48 | 13.99 | 1.700 | 31.500 |
| 125.48 | 14.07 | 2.200 | 30.000 |
| 129.18 | 14.07 | 2.000 | 27.750 |
| 133.18 | 14.14 | 2.050 | 30.000 |
| 137.08 | 14.14 | 1.800 | 29.250 |
| 141.58 | 14.20 | 1.800 | 33.750 |
| 145.08 | 14.29 | 2.000 | 26.250 |
| 149.08 | 14.29 | 1.900 | 30.000 |
| 152.98 | 14.31 | 1.900 | 29.250 |
| 156.88 | 14.35 | 1.900 | 29.250 |
| 160.93 | 14.35 | 1.800 | 30.375 |
| 164.83 | 14.35 | 1.700 | 29.250 |
| 168.78 | 14.40 | 1.700 | 29.625 |
| 172.78 | 14.40 | 1.650 | 30.000 |
| 176.78 | 14.48 | 1.600 | 30.000 |
| 180.78 | 14.50 | 1.600 | 30.000 |
| 184.68 | 14.50 | 1.500 | 29.250 |
| 188.78 | 14.50 | 1.550 | 30.750 |
| 192.68 | 14.51 | 1.500 | 29.250 |
| 196.73 | 14.57 | 1.600 | 30.375 |
| 200.78 | 14.62 | 1.500 | 30.375 |
| 204.78 | 14.62 | 1.600 | 30.000 |
| 209.28 | 14.65 | 1.600 | 33.750 |
| 213.28 | 14.65 | 1.800 | 30.000 |
| 216.78 | 14.71 | 1.950 | 26.250 |
| 220.78 | 14.71 | 1.950 | 30.000 |
| 224.78 | 14.71 | 1.550 | 30.000 |
| 228.58 | 14.71 | 1.550 | 28.500 |
| 232.70 | 14.79 | 1.550 | 30.900 |
| 236.70 | 14.79 | 1.450 | 30.000 |
| 240.70 | 14.79 | 1.500 | 30.000 |
| 244.50 | 14.79 | 1.500 | 28.500 |
| 248.50 | 14.81 | 1.550 | 30.000 |
| 252.50 | 14.81 | 1.400 | 30.000 |
| 256.50 | 14.81 | 1.350 | 30.000 |
| 260.50 | 14.86 | 1.350 | 30.000 |
| 265.00 | 14.86 | 1.400 | 33.750 |
| 269.00 | 14.87 | 1.450 | 30.000 |

# APPENDIX B

## Produced Water Analysis

**Table - B.1**

**Produced Water Analysis for Run # 7**

**Injected Water : Sea Water**

| WATER INJECTED (P.V.) | TDS (mg/l) | $Na^+$ (mg/l) | $Ca^{++}$ (mg/l) | $Mg^{++}$ (mg/l) | $Sr^{++}$ (mg/l) | $Ba^{++}$ (mg/l) | $SO_4^{--}$ (mg/l) | $Cl^-$ (mg/l) | $HCO_3^-$ (mg/l) |
|---|---|---|---|---|---|---|---|---|---|
| 0.418 | 185242.9 | 47840 | 20140 | 1045 | 579.0 | 3.30 | 1082.0 | 114500 | 53.70 |
| 0.536 | 128685.3 | 34170 | 12020 | 1305 | 337.0 | 4.63 | 1775.0 | 79020 | 53.70 |
| 0.722 | 87788.8 | 24130 | 6900 | 1505 | 169.0 | 1.18 | 2020.0 | 53010 | 53.70 |
| 0.951 | 63629.3 | 18340 | 2720 | 1660 | 65.4 | 0.30 | 3960.0 | 36830 | 53.60 |
| 1.182 | 60342.7 | 17790 | 1975 | 1695 | 43.8 | 0.30 | 4385.0 | 34400 | 53.60 |
| 1.434 | 59283.4 | 17430 | 1545 | 1780 | 34.5 | 0.32 | 4710.0 | 33730 | 53.60 |
| 1.660 | 57453.3 | 17290 | 1170 | 1825 | 21.8 | 0.33 | 4340.0 | 32760 | 46.20 |
| 1.889 | 57464.1 | 17210 | 908 | 1830 | 24.6 | 0.30 | 4295.0 | 33150 | 46.20 |
| 2.123 | 58853.8 | 17570 | 874 | 1895 | 23.3 | 0.30 | 4385.0 | 34060 | 46.20 |
| 2.349 | 58389.0 | 17710 | 852 | 1920 | 22.8 | 0.30 | 4385.0 | 33450 | 48.90 |
| 2.569 | 61242.0 | 18540 | 865 | 2035 | 22.8 | 0.30 | 4630.0 | 35100 | 48.90 |
| 2.794 | 60851.8 | 18000 | 826 | 1975 | 21.6 | 0.30 | 5410.0 | 34570 | 48.90 |
| 3.019 | 57592.4 | 17610 | 803 | 1930 | 21.2 | 0.30 | 4350.0 | 32830 | 47.90 |
| 3.244 | 58184.0 | 17730 | 795 | 1960 | 20.2 | 0.30 | 4420.0 | 33210 | 47.90 |
| 3.456 | 59571.1 | 18350 | 807 | 2035 | 20.9 | 0.30 | 4560.0 | 33750 | 47.90 |
| 3.676 | 57883.4 | 17630 | 770 | 1955 | 20.2 | 0.30 | 4375.0 | 33090 | 42.90 |
| 3.902 | 59863.6 | 18030 | 780 | 2015 | 20.4 | 0.30 | 4495.0 | 34480 | 42.90 |
| 4.335 | 58948.1 | 18000 | 774 | 2020 | 20.1 | 0.30 | 4485.0 | 33600 | 48.70 |
| 4.954 | 61381.4 | 18530 | 775 | 2100 | 20.2 | 0.30 | 4645.0 | 35260 | 50.90 |
| 5.576 | 58483.9 | 17780 | 752 | 2020 | 19.8 | 0.30 | 4470.0 | 33400 | 41.80 |
| 6.200 | 64064.7 | 19440 | 787 | 2215 | 20.6 | 0.30 | 4885.0 | 36680 | 36.80 |
| 7.121 | 60609.8 | 18330 | 745 | 2105 | 19.7 | 0.30 | 4613.0 | 34760 | 36.80 |

## Table - B.2

## Produced Water Analysis for Run # 8

## Injected Water : Wasia Water

| WATER INJECTED (P.V.) | TDS (mg/l) | $Na^+$ (mg/l) | $Ca^{++}$ (mg/l) | $Mg^{++}$ (mg/l) | $Sr^{++}$ (mg/l) | $Ba^{++}$ (mg/l) | $SO_4^{--}$ (mg/l) | $Cl^-$ (mg/l) | $HCO_3^-$ (mg/l) |
|---|---|---|---|---|---|---|---|---|---|
| 0.400 | 207486.4 | 47330 | 26810 | 580.00 | 770.0 | 6.80 | 993.0 | 130950 | 46.70 |
| 0.508 | 115130.7 | 26680 | 15340 | 181.00 | 436.0 | 7.00 | 1100.0 | 71340 | 46.70 |
| 0.728 | 39409.2 | 8960 | 5450 | 57.10 | 149.0 | 2.40 | 1014.0 | 23730 | 46.70 |
| 0.951 | 18240.4 | 4005 | 2475 | 39.10 | 36.8 | 1.20 | 1020.0 | 10630 | 33.30 |
| 1.180 | 12236.9 | 2600 | 1575 | 39.10 | 36.8 | 0.74 | 1030.0 | 6922 | 33.30 |
| 1.393 | 7727.7 | 1580 | 806 | 63.30 | 13.8 | 0.33 | 1155.0 | 4076 | 33.30 |
| 1.610 | 6307.2 | 1395 | 656 | 75.50 | 10.1 | 0.32 | 1120.0 | 3017 | 33.30 |
| 1.825 | 6679.4 | 1440 | 705 | 67.80 | 11.0 | 0.30 | 1140.0 | 3282 | 33.30 |
| 2.042 | 7931.1 | 1710 | 920 | 59.90 | 17.5 | 0.39 | 1095.0 | 4095 | 33.30 |
| 2.256 | 7176.2 | 1525 | 827 | 56.50 | 14.9 | 0.55 | 1095.0 | 3624 | 33.30 |
| 2.473 | 7058.2 | 1530 | 809 | 58.40 | 13.9 | 0.30 | 1130.0 | 3486 | 30.90 |
| 2.672 | 7199.8 | 1555 | 808 | 63.00 | 14.3 | 0.59 | 1150.0 | 3578 | 30.90 |
| 2.848 | 6701.2 | 1470 | 766 | 58.00 | 12.9 | 0.43 | 1115.0 | 3248 | 30.90 |
| 3.060 | 6901.4 | 1515 | 782 | 59.10 | 13.3 | 0.43 | 1150.0 | 3352 | 29.60 |
| 3.282 | 9663.6 | 2050 | 1210 | 58.50 | 25.9 | 0.57 | 1065.0 | 5234 | 29.60 |
| 3.605 | 8501.4 | 1845 | 1055 | 48.70 | 21.7 | 0.42 | 1060.0 | 4441 | 29.60 |
| 4.133 | 7063.4 | 1565 | 737 | 75.80 | 12.2 | 0.40 | 1210.0 | 3428 | 35.00 |
| 4.684 | 6529.5 | 1440 | 695 | 69.00 | 11.2 | 0.30 | 1160.0 | 3126 | 28.00 |
| 5.224 | 6783.6 | 1475 | 750 | 58.80 | 12.6 | 0.41 | 1130.0 | 3329 | 27.80 |
| 5.979 | 6308.6 | 1385 | 644 | 78.50 | 10.2 | 0.40 | 1120.0 | 3040 | 30.50 |

## Table - B.3

## Produced Water Analysis for Run # 9

## Injected Water : 10% Arab-D Water

| WATER INJECTED (P.V.) | TDS (mg/l) | $Na^+$ (mg/l) | $Ca^{++}$ (mg/l) | $Mg^{++}$ (mg/l) | $Sr^{++}$ (mg/l) | $Ba^{++}$ (mg/l) | $SO_4^{--}$ (mg/l) | $Cl^-$ (mg/l) | $HCO_3^-$ (mg/l) |
|---|---|---|---|---|---|---|---|---|---|
| 0.438 | 198502.6 | 44960 | 27000 | 0737 | 801.0 | 14.10 | 552.0 | 124400 | 38.5 |
| 0.622 | 146361.5 | 32860 | 19710 | 1110 | 612.0 | 9.00 | 352.0 | 91670 | 38.5 |
| 0.865 | 112621.1 | 24980 | 14870 | 1495 | 489.0 | 5.59 | 183.0 | 70560 | 38.5 |
| 1.118 | 105422.3 | 23390 | 13590 | 1710 | 459.0 | 4.71 | 118.0 | 66120 | 30.6 |
| 1.359 | 109064.1 | 23830 | 13680 | 1840 | 466.0 | 4.55 | 103.0 | 69110 | 30.6 |
| 1.600 | 103618.7 | 22960 | 13100 | 1820 | 448.0 | 5.47 | 84.7 | 65170 | 30.6 |
| 1.843 | 102733.8 | 23090 | 13070 | 1860 | 449.0 | 4.01 | 76.6 | 64160 | 24.3 |
| 2.048 | 102822.7 | 22860 | 12900 | 1870 | 444.0 | 4.05 | 70.4 | 64650 | 24.3 |
| 2.324 | 102722.7 | 22860 | 12880 | 1880 | 444.0 | 4.05 | 70.4 | 64560 | 24.3 |
| 2.592 | 109029.7 | 23880 | 13210 | 1940 | 461.0 | 3.76 | 66.7 | 69440 | 28.3 |
| 2.833 | 122866.0 | 25760 | 14210 | 2095 | 497.0 | 4.09 | 61.7 | 80210 | 28.3 |
| 3.058 | 103291.3 | 22680 | 12520 | 1855 | 437.0 | 3.72 | 57.3 | 65710 | 28.3 |
| 3.300 | 100506.1 | 22120 | 12160 | 1810 | 426.0 | 3.54 | 55.5 | 63900 | 31.1 |
| 3.541 | 100891.1 | 21950 | 12050 | 1805 | 422.0 | 3.57 | 59.5 | 64570 | 31.1 |
| 3.782 | 101955.4 | 22390 | 12270 | 1835 | 431.0 | 3.57 | 54.8 | 64940 | 31.1 |
| 4.023 | 102619.9 | 22320 | 12170 | 1830 | 429.0 | 3.45 | 53.3 | 65780 | 34.2 |
| 4.624 | 104138.6 | 22810 | 12480 | 1885 | 439.0 | 3.53 | 52.2 | 66430 | 38.9 |
| 5.343 | 104642.6 | 22820 | 12540 | 1895 | 439.0 | 3.57 | 56.2 | 66850 | 38.9 |
| 5.945 | 103398.2 | 22820 | 12580 | 1905 | 440.0 | 3.59 | 55.9 | 65550 | 43.8 |
| 6.540 | 100905.1 | 21980 | 12100 | 1835 | 424.0 | 3.39 | 54.8 | 64460 | 48.0 |
| 7.140 | 106315.0 | 23390 | 12870 | 1960 | 451.0 | 3.79 | 53.7 | 67530 | 56.6 |

**Table - B.4**

**Produced Water Analysis for Run # R-7**

**Injected Water : Sea Water**

| WATER INJECTED (P.V.) | TDS (mg/l) | $Na^{+}$ (mg/l) | $Ca^{++}$ (mg/l) | $Mg^{++}$ (mg/l) | $Sr^{++}$ (mg/l) | $Ba^{++}$ (mg/l) | $SO_4^{--}$ (mg/l) | $Cl^{-}$ (mg/l) | $HCO_3^{-}$ (mg/l) |
|---|---|---|---|---|---|---|---|---|---|
| 0.442 | 221900.4 | 54930 | 24240 | 1430 | 760.0 | 7.71 | 1620.0 | 138900 | 12.70 |
| 0.508 | 162787.2 | 41260 | 16810 | 1370 | 520.0 | 4.55 | 1710.0 | 101100 | 12.70 |
| 0.572 | 124933.9 | 32200 | 11850 | 1410 | 356.0 | 5.20 | 2520.0 | 76580 | 12.70 |
| 0.683 | 104503.1 | 27770 | 8300 | 1590 | 249.0 | 1.43 | 1660.0 | 64920 | 12.70 |
| 0.794 | 82345.6 | 22820 | 5350 | 1700 | 151.0 | 1.91 | 3610.0 | 48700 | 12.70 |
| 0.914 | 77583.7 | 21910 | 4050 | 1890 | 110.0 | 1.00 | 4260.0 | 45350 | 12.70 |
| 1.294 | 60452.5 | 17760 | 1920 | 1850 | 48.8 | 1.00 | 4690.0 | 34170 | 12.70 |
| 2.322 | 56038.7 | 16890 | 982 | 1900 | 20.8 | 1.00 | 4150.0 | 32060 | 34.90 |
| 6.494 | 59166.5 | 17990 | 758 | 2120 | 13.9 | 1.00 | 4390.0 | 33870 | 23.60 |